Planning of the Ontario Hydro East System

Part I · Volume 2

Report number 573 SP · June 1, 1976

PLANNING OF THE
ONTARIO HYDRO EAST SYSTEM

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Figure 4-1

Ontario Energy
Supply and Demand 1959

BTUx10[12]

	Primary Energy					
	Coal	Oil	Gas	Hydraulic	Sub Total	Secondary Electricity
Supply						
Production in Ontario	0	5.8	17.3	377.0	400.1	
Imports from Outside Canada	313.1	52.7	12.4	0	378.2	1.6
Imports from Other Provinces	11.4	537.1	64.4	0	612.9	19.2
Inventory Depletion	16.4	-14.9	-.1	0	1.4	
TOTAL	340.9	580.7	94.0	377.0	1392.6	20.8
Conversion etc.						
Electricity Produced	2.9+.2	.1	.2	110.5	113.9	113.9
Elec. Production Losses	9.7	.1	.7	266.5	277.0	
Other Conversion Losses	12.0	29.1	0	0	41.1	
Sub Total	24.6	29.3	.9	377.0	432.0	
Final Demand = Net Supply of Primary and Secondary Energy	316.3	551.4	93.1	0	960.8	134.7
Exports	1.1	3.3	0	0	4.4	13.2
Transport	17.6	231.3	0	0	248.9	0
Domestic Farm	41.2	174.3	39.6	0	255.1	30.0
Commercial	31.7	18.5	9.9	0	60.1	17.8
Industrial	236.6	74.0	38.6	0	349.2	59.1
Consumption by Energy Supply Industries	0	39.8	2.8	0	42.7	14.7
Losses etc.	-11.9	10.1	2.2	0	-.4	0

* .2 from wood

** computed at coal equivalent 10,000 BTU/kWh

Source: "Detailed Energy Supply and Demand in Canada 1972", Statistics Canada 57-207

Figure 4-2

Ontario Energy
Supply and Demand 1972

$BTU x 10^{12}$

	Primary Energy: Coal	Oil	Gas	Hydraulic	Sub Total	Secondary Electricity
Supply						
Production in Ontario	0	5.1	12.3	473.8*	491.2	
Imports from Outside Canada	460.9	28.8	15.6	0	505.3	6.0
Imports from Other Provinces	3.5	987.2	573.2	0	1563.9	28.6
Inventory Depletion	-43.9	-21.3	11.8	0	-53.4	
TOTAL	420.5	999.8	612.9	473.8	2507.0	34.6
Conversion etc.						
Electricity Produced	77.5	1.4	15.4	161.7	256.0	256.0
Elec. Production Losses	138.7	6.4	41.5	312.1	498.7	
Other Conversion Losses	16.8	14.9	.1	0	31.8	
Sub Total	233.0	22.7	57.0	473.8	786.5	
Final Demand = Net Supply of Primary and Secondary Energy	187.5	977.1	555.9	0	1720.5	290.6
Exports	2.6	16.3	17.7	0	36.6	20.7
Transport	3.0	442.3	0	0	445.3	0
Domestic Farm	2.6	210.5	117.1	0	330.2	66.9
Commercial	4.3	116.3	113.8	0	234.4	75.2
Industrial	177.0	126.0	265.5	0	568.5	103.5
Consumption by Energy Supply Industries	0	55.8	34.2	0	90.0	24.3
Non-Energy	0	1.5	0	0	1.5	0
Losses etc.	-2.0	8.4	7.6	0	14.0	0

* computed at coal equivalent 10,000 BTU/kWh

Source: "Detailed Energy Supply and Demand in Canada 1972", Statistics Canada 57-207

Figure 4-3

Canadian Mineral Energy Reserves 1973

Type	Units	Proven(1)	Ultimately Recoverable(2)	BTU/Unit	Heat Content, $BTU\times10^{15}$ Proven	Heat Content, $BTU\times10^{15}$ Ultimately Recoverable
Coal(3)	Short Tons$\times10^9$	10.2	120.2	23.0×10^6/st	250.7	2765
*Oil	Barrels$\times10^9$	9.7	83.1	5.8×10^6/bbl	56.3	482
Gas(4)	Cubic Feet$\times10^{12}$	52.9	711.5	1.0×10^3/cf	52.9	711
U_3O_8	Short Tons$\times10^3$	399.0	930.0	**5.8×10^{11}/st	231.4	5394
TOTAL CONV.					591.3	9352
Tar Sands and Heavy Oil	bbl$\times10^9$	64.9	330.0	5.8×10^6/bbl	376.4	1914
TOTAL					967.0	11266

(1) Canadian Petroleum Association December 1972

(2) Geological Survey of Canada March 1973

(3) "Energy Policy for Canada" page 59

(4) CPA average estimates as of April 1975 were 81.0 proven, 509 ult. rec. (Canadian National Gas Supply and Requirements National Energy Board April 1975)

* Excluding Tar Sands and Heavy Oil.

** Based on 29,000 kWh per lb evaluated at 10,000 BTU/kWh.

Source: "An Energy Policy for Canada" Vol. 2

FIGURE 4-4

Projections of Gross National Expenditure - $Billions expressed in 1971$

Year	Economic Council of Canada - 12th Review: Actual	Economic Council of Canada - 12th Review: Potential[2]		Projections of Historical Time Models, 1926-1975: Prediction With Autoregression: Upper Value	Prediction With Autoregression: Expected Value	Prediction With Autoregression: Lower Value	Logistic Model Expected Value[3]	Projection of 1926-1975 Least Squares Trend (Growth 4.86%p.a.)
1973	105.912	105.912						100.564
1974	108.862	111.737						105.446
1975	108.350	117.883						110.565
	Economic Council of Canada - 12th Review: Control[1]	Potential	Attainable Target					
1976	114.708	124.366	116.042	117.9	114.0	110.0	111.8	115.932
1977	121.820	131.206	123.702	125.7	119.8	113.9	116.5	121.560
1978	128.520	138.423	130.752	133.6	125.9	118.2	121.2	127.462
1979	135.545	146.036		141.6	132.2	122.9	126.2	133.650
1980	142.956	154.068		150.0	138.9	127.8	131.2	140.138
1981	150.103	162.542		158.6	145.8	133.0	136.5	146.941
1982	156.857	171.481		167.7	153.1	138.5	141.8	154.075
1983	162.613	180.913		177.1	160.7	144.2	147.4	161.554
1984	168.580	190.863		187.0	168.6	150.2	153.0	169.397
1985	174.766	201.361		197.3	176.9	156.5	158.8	177.621
% Growth Rates, 1973-1985	4.26	5.50		5.32	4.37	3.31	3.43	

1. Scenario 2 - Favorable External Environment, Moderate Energy Prices, Medium Immigration.
2. At 5.5% from 1973.
3. $\frac{1000}{GNE} = 161.86 + 8855.82 \times (0.951374)^{(YR-1926)}$ (Max 617.8)

FIGURE 4-5

% Deviation of Projections from 1926-1975 Least Squares Trend

	Real Gross National Expenditure: Actual	Potential	Target	Prediction With Autoregression: Upper	Prediction With Autoregression: Expected	Prediction With Autoregression: Lower	Logistic
1973	5.32	5.32					
1974	3.24	5.96					
1975	- 2.00	6.57					
	Control						
1976	- 1.06	7.27	0.09	1.71	- 1.70	- 5.12	- 3.55
1977	0.21	7.93	1.76	3.44	- 1.45	- 6.34	- 4.20
1978	0.83	8.60	2.58	4.81	- 1.22	- 7.27	- 4.91
1979	1.42	9.27		5.95	- 1.08	- 8.04	- 5.57
1980	2.01	9.94		7.03	- 0.88	- 8.80	- 6.38
1981	2.15	10.62		7.93	- 0.78	- 9.48	- 7.10
1982	1.80	11.30		8.84	- 0.63	-10.11	- 7.97
1983	0.66	11.98		9.62	- 0.53	-10.74	- 8.76
1984	- 0.48	12.67		10.39	- 0.47	-11.33	- 9.68
1985	- 1.61	13.36		11.08	- 0.40	-11.89	-10.60

FIGURE 4-6

East System Peak Load Projections Derived from GNE, in Megawatts

	Load Actual	Load Computed from GNE: Actual GNE	Potential GNE
1973	12376	12706	12706
1974	13250	13438	13630
1975	13800P	13967	14618

	1976 Weather-Corrected Forecast	Economic Council of Canada - 12th Review -			Prediction With Autoregression			Logistic Projection
		Control	Potential	Target	Upper	Expected	Lower	
1976	14733	14914	15584	15160	15140	14861	14578	14709
1977	15861	16105	16768	16297	16385	15959	15524	15715
1978	17197	17305	18017	17500	17672	17111	16534	16764
1979	18265	18577	19344		19026	18330	17610	17867
1980	19471	19934	20762		20460	19624	18756	19029
1981	20701	21335	22278		21986	21002	19979	20259
1982	22106	22772	23902		23612	22472	21282	21560
1983	23609	24199	25643		25348	24042	22672	22938
1984	25215	25715	27510		27204	25718	24156	24398
1985	26930	27325	29512		29187	27508	25738	25943
% Growth Rates, 1973-1985								
	6.69	6.82	7.51		7.41	6.88	6.29	6.36

FIGURE 4-7

% Deviations from Prediction With Autoregression of GNE

	1976 Forecast	Economic Council of Canada - 12th Review -			Prediction With Autoregression			Logistic Projection
		Control	Potential	Target	Upper	Expected	Lower	
1976	-0.86	0.36	4.86	2.01	1.88	0	-1.90	-1.02
1977	-0.61	0.91	5.07	2.12	2.66	0	-2.72	-1.53
1978	-0.50	1.13	5.29	2.27	3.28	0	-3.37	-2.03
1979	-0.35	1.35	5.53		3.80	0	-3.92	-2.52
1980	-0.78	1.58	5.80		4.26	0	-4.42	-3.03
1981	-1.43	1.59	6.07		4.69	0	-4.87	-3.54
1982	-1.63	1.33	6.36		5.07	0	-5.29	-4.06
1983	-1.80	0.65	6.66		5.43	0	-5.70	-4.59
1984	-1.96	-0.01	6.97		5.78	0	-6.07	-5.13
1985	-2.10	-0.66	7.29		6.10	0	-6.43	-5.69

FIGURE 4-8

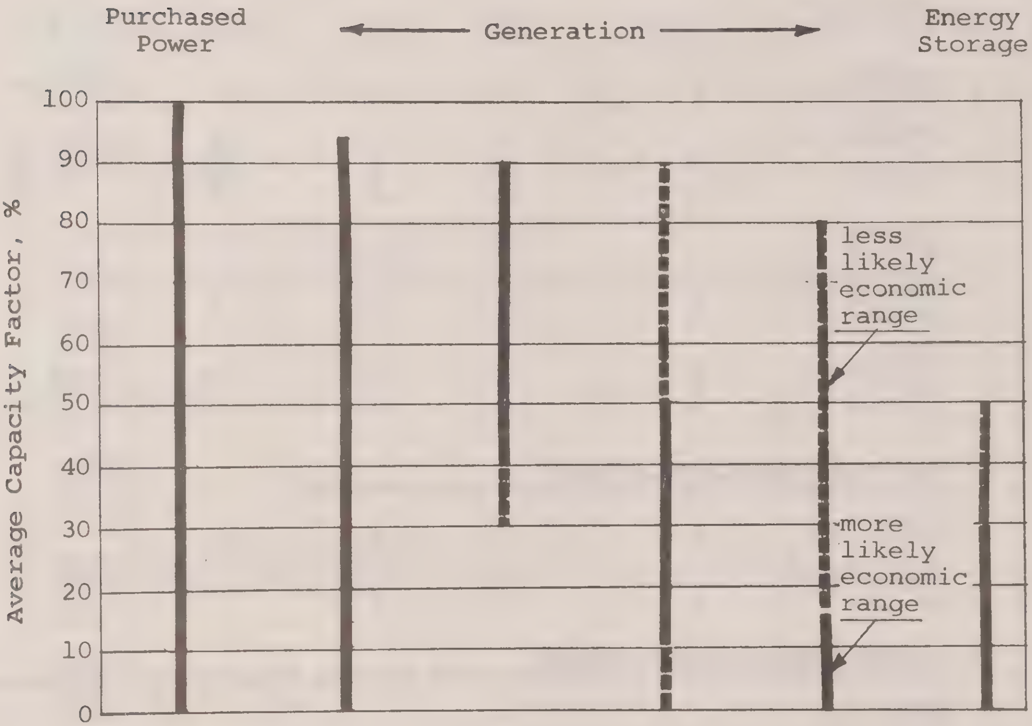
East System Forecast Error (%)*

Year of Forecast	Years after Forecast									
	1	2	3	4	5	6	7	8	9	10
1950	- 5.6	-11.1	-14.7	-16.6	-18.1	-25.4				
1951	1.1	0.1	- 0.4	- 1.5	- 9.3					
1952	2.2	5.0	6.1	- 2.0	- 4.1					
1953	2.3	4.0	- 2.5	- 3.9	- 4.1	- 6.6				
1954	- 0.4	- 5.2	- 6.0	- 5.2	- 7.4					
1955	- 3.0	- 2.5	- 1.5	- 3.2	- 6.7	- 5.3				
1956	1.6	5.7	4.8	2.0	3.7	5.2				
1957	2.8	1.5	- 0.9	3.4	6.3	6.6	6.2	6.7		
1958	- 0.9	- 2.2	2.1	4.1	3.8	1.4	1.4	- 1.8	- 4.7	- 3.4
1959	0.1	2.8	6.1	6.4	4.1	4.5	0.6	- 2.9	- 2.0	- 7.4
1960	2.6	5.3	6.0	3.2	3.6	0.4	- 2.9	- 1.6	- 6.6	- 6.2
1961	1.9	3.2	0.8	0.6	- 3.0	- 5.4	- 3.6	- 8.3	- 7.8	- 8.5
1962	1.0	- 1.9	- 1.6	- 4.8	- 7.5	- 6.6	-10.6	-10.1	-10.7	- 7.1
1963	- 2.7	- 2.3	- 6.0	- 8.6	- 7.1	-11.6	-10.8	-11.3	- 7.5	-10.7
1964	- 1.6	- 4.4	- 6.5	- 5.3	- 9.4	- 8.7	- 9.4	- 6.4	- 4.4	- 5.1
1965	- 1.2	- 3.7	- 1.5	- 5.9	- 5.2	- 5.8	- 1.7	- 5.1	- 5.6	0.0
1966	- 1.0	0.2	- 5.9	- 4.2	- 4.8	- 0.6	- 4.0	- 4.4	1.7	0.1
1967	1.2	- 3.1	- 2.0	- 2.2	2.4	- 0.8	- 1.0	5.5	4.2	
1968	- 0.3	1.7	1.7	7.0	3.2	2.7	9.5	8.2		
1969	0.9	1.9	7.0	5.2	5.6	13.0	11.3			
1970	1.0	6.7	5.7	5.5	12.0	10.9				
1971	6.2	3.4	3.6	10.0	9.0					
1972	1.9	2.0	8.6	7.2						
1973	0.4	7.9	7.5							
1974	6.3	6.3								
1975	1.1									

* Difference between forecast made 1 to 10 years prior to year indicated divided by actual load. A negative sign indicates too low.

FIGURE 6.1-1

Alternative Types of Power Sources That Can Reasonably Be Considered
For the Ontario Hydro System
For the Period Up to 1995



	Hydraulic	CANDU Nuclear	Fossil-Steam	Gas Turbines
Capital Cost	high	high	medium	low
Energy Cost	low	low	medium	high
Dependence on Non-Indigenous Fuel	none	low	high	high

FIGURE 6.1-2 - Sheet 1

Estimate of Ontario's Remaining Conventional Hydroelectric Potential, in the Larger Developments (Note 1)

River and Site	Hours of Peak Output (Note 2)	Estimated Increments in Peak Capacity in MW: Installed	Peak Capacity in MW: Dependable	Average Annual Energy, in Average MW	Capacity Factor of Increment, % (Note 3)
A. NEW SITES UNAFFECTED BY ALBANY RIVER DIVERSIONS					
ABITIBI					
Long Sault Rapids	2	80	69	27	39
Nine Mile Rapids	-4 (Note 4)	128	121	66	54
	-2 (Note 4)	256	243	71	29
MATTAGAMI					
Grand Rapids	-4 (Note 5)	109	102	62	61
	-2 (Note 5)	218	190	77	41
MADAWASKA					
Highland Falls	2	95	91	16	18
MISSINAIBI					
Thunderhouse Falls	-7	13	13	10	77
	-2	42	42	20	48
Long Rapids	-7	31	31	25	81
	-2	100	100	49	49
MISSISSAGI					
Gros Cap	2	262	258	47	18
MOOSE					
Grey Goose	2	188	175	74	42
Renison	2	188	186	76	41
WHITE					
Chigamiwingum	8	16	15	14	93
Umbata	8	14	14	12	86
Chicagouse	8	11	11	10	91
B. NEW SITES AFFECTED BY ALBANY DIVERSIONS POTENTIAL ASSUMING CONTINUATION OF EXISTING ALBANY DIVERSIONS					
ENGLISH					
Maynard Falls	8	51	46	27	59
LITTLE JACKFISH					
Mileage 12.5	8	38	36	26	72
Mileage 7.5	8	46	46	33	72
C. NEW SITES AFFECTED BY ALBANY DIVERSIONS POTENTIAL ASSUMING TERMINATION OF EXISTING ALBANY DIVERSIONS (to English and Nipigon Rivers)					
ENGLISH					
Maynard Falls	N/A				
LITTLE JACKFISH					
Mileage 12.5	N/A				
Mileage 7.5	N/A				
ALBANY					
Achapi	4	131	131	33	25
Eskakwa	4	268	166	119	72
Miminiska	4	57	57	35	61
Frenchman	4	95	95	61	64
Washi	4	73	73	47	64
Kagiami	4	117	117	83	71
Martin	4	70	70	51	73
Nottik	4	73	73	55	75
Buffaloskin	4	101	101	83	82
Wabimeig	8	217	119	163	137
Chard	8	536	536	376	70
Hat	8	422	399	284	71
Blackbear	8	402	402	279	69
Biglow	8	382	382	268	70
Stooping	8	308	308	206	67
Total of Albany Developments:		3252	3029	2143	71

The above capacities presume the following diversions are made into the Albany River:
Whiteclay Diversion
Winisk-Attawapiscat Diversion

FIGURE 6.1-2

FIGURE 6.1-2 - Sheet 2

River and Site	Hours of Peak Output (Note 2)	Estimated Increments in Peak Capacity in MW: Installed	Dependable	Average Annual Energy, in Average MW	Capacity Factor of Increment, % (Note 3)
D. EXTENSIONS OR REDEVELOPMENT OF EXISTING STATIONS					
Schemes Unaffected by Albany Diversions					
ABITIBI					
Canyon	2	790	714	20	3
Otter Rapids	2	175	161	4	2
MATTAGAMI					
Little Long	2	122	106	17	16
Harmon	2	136	107	18	17
Kipling	2	136	118	19	16
Smoky Falls	-4 (Note 6)	102	100	43	43
	-2 (Note 6)	157	239	66	28
MISSISSAGI					
Red Rock Falls	2-3	36	33	2	6
OTTAWA					
Otto Holden	2-3	202	156	6	4
Des Joachims	2	696	640	19	3
MONTREAL					
Hound Chute/Ragged Chute Redevelopment	2	98	98	19	19
E. EXTENSIONS OR REDEVELOPMENT OF EXISTING STATIONS					
Schemes Affected by Albany Diversions — Potential Assuming Continuation of Existing Diversions (to English and Nipigon Rivers)					
ENGLISH					
Ear Falls	8	7	5	4	80
NIAGARA					
SAB #2 (Existing Tunnels)	1/2	305	199	0	0
SAB #3 (New Tunnel)	1	458	501	138	28
NIPIGON					
Pine Portage Ext	8	27	22	1	5
Cameron Falls Ext	8	18	17	2	12
Alexander Ext	8	19	13	2	15
Schemes Affected by Albany Diversions — Potential Assuming Termination of Existing Diversions (to English and Nipigon Rivers)					
ENGLISH					
Ear Falls	N/A				
NIPIGON					
Pine Portage Ext	N/A				
Cameron Falls Ext	N/A				
Alexander Ext	N/A				
NIAGARA					
SAB #2 (Existing Tunnels)	1/2	305	199	0	0
SAB #3 (New Tunnel)	1	458	501	138	28

Note 1: The table includes new sites capable of producing 10 or more average MW. It does not include potential sites on the Severn, Winisk, and Attawapiskat Rivers because little data are available on them.

Note 2: These are the hours of operation at the dependable peak capacity that the site can provide under extremely low water supply conditions.

Note 3: The Capacity Factor corresponds to the Increment in Average Annual Energy and the Increment in Dependable Peak Capacity.

Note 4: The 4-hour peak applies if Nine Mile Rapids is developed in step with the existing generating station at Otter Rapids.
The 2-hour peak applies if Otter Rapids is extended to provide 2-hour peaking, and Nine Mile Rapids is developed in step with it.

Note 5: The 4-hour peak applies if Grand Rapids is developed in step with the existing generating stations at Little Long, Harmon, and Kipling.
The 2-hour peak applies if Little Long, Harmon, and Kipling are extended to provide 2-hour peaking, and Grand Rapids is developed in step with them.

Note 6: The 4-hour peak applies if the existing generating station at Smoky Falls is redeveloped in step with the existing generating station at Little Long.
The 2-hour peak applies if Little Long is extended to provide 2-hour peaking, and Smoky Falls is redeveloped in step with it.

FIGURE 6.1-2

FIGURE 6.1-3

Some Aboveground Pumped Storage Sites
Studied by Ontario Hydro Since 1965

			Generating Capability			
Site	Hours of Pumping	Hrs/Day of Generating	Installed Peak Capacity MW	Dependable Peak Capacity MW	Ave. Annual Energy MW	Annual Capacity Factor**
Delphi Point	8 hr/day+weekends	4	2912	3060	378	12
	8 hr/day+weekends	6	2000	2100	378	18
	8 hr/day+weekends	8	906	960	231	24
	10 hr/day	8	1450	1530	378	25
Matabitchuan						
- HWL 940*		8	440	429	105	24
- HWL 920*		8	234	226	56	25
Jordan-Erie	daily cycle	4	1120	1031	132	13
	weekly cycle	10.5	1120	1031	326	32
	annual cycle	(16 for 4 mos) (4 for 8 mos)	1120	1031	253	25

* HWL refers to high water level in upper reservoir.
** Based on average energy and dependable peak capacity when generating.

FIGURE 6.1-4

Commercially Available Thermal Generation Equipment

	Normal Fuel	Alternative Fuels++	Electrical Production Efficiency %	Energy Released Per Unit of Electricity Produced (a) to Cooling Water	(b) to Atmosphere	Maximum Unit Size MW	Most Appropriate Modes of Operation
Sub-Critical Fossil-Steam	Coal	Gas or Bunker Oil	38	1.3	0.3	900*	Intermediate or Peaking
	Bunker Oil	Gas or Crude Oil	38	1.3	0.3	"	"
	Crude Oil	Gas or Bunker Oil	38	1.3	0.3	"	"
	Gas	Bunker Oil	37	1.3	0.4	"	"
Super-Critical Fossil-Steam	Coal	Gas or Bunker Oil	39	1.3	0.3	1300+	Base
	Bunker Oil	Gas or Crude Oil	39	1.3	0.3	"	"
	Crude Oil	Gas or Bunker Oil	39	1.3	0.3	"	"
	Gas	Bunker Oil	38	1.3	0.3	"	"
Gas Turbine	#2 Oil	Gas	29	0.0	2.4	100	Peaking or Reserve
	Gas	#2 Oil	28	0.0	2.6	"	"
Gas Turbine/ Steam Turbine	#2 Oil	Gas	40	0.8	0.7	500	Intermediate or Peaking
	Gas	#2 Oil	39	0.8	0.8	"	"
CANDU Nuclear	Uranium	-	30	2.3	0.0	1250	Base

* Apparent limit on size of a tandem compound steam turbine (using a single generator).
\+ Apparent limit on size of a cross compound steam turbine (using two generators).
++ Unless a unit is specifically designed to burn alternative fuels, considerable equipment modification may be required.

FIGURE 6.1-5

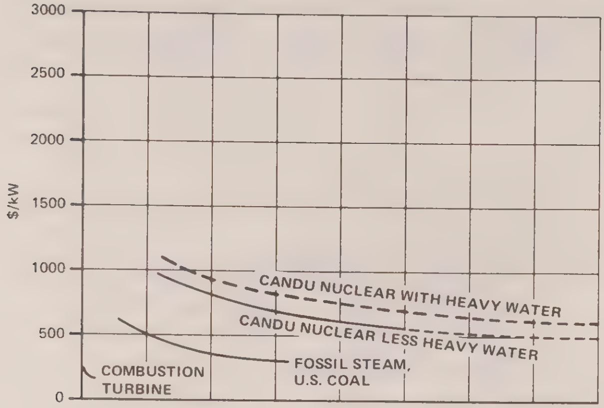
1975 Forecast of New Generating Unit Outage Indices for Use in Studies of Future System Development

Year of Operation		Adjusted Forced Outage Rate (AFOR), % 1	2	3	4	5	Maintenance Outage Factor (MOF), % 1	2	3	4	5
CANDU Nuclear Units											
	200	15	12	10	8	8	8	6	4	4	4
	500	15	12	10	9	9	8	6	4	4	4
	850	15	13	12	10	10	8	6	4	4	4
	1200	22	17	15	14	12	10	8	6	5	5
Fossil Steam Units											
Lignite	150/200	15	13	11	9	9	6	5	4	4	4
Lignite	300	15	13	11	9	9	6	5	4	4	4
Bituminous Coal, or Oil	500	15	12	10	8	8	6	4	4	4	4
	750	17	15	13	10	10	7	5	5	5	5
	1000/1200	20	18	16	12	12	8	6	6	5	5
Combustion Turbine Units		15	15	15	15	15	(included in POF)				
Hydraulic Units		.5	.5	.5	.5	.5	(included in POF)				

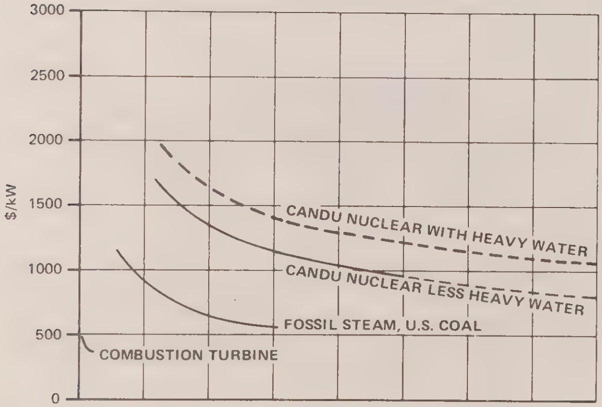
Year of Operation		Planned Outage Factor (POF), % 1	2	3	4	5	Capability % 1	2	3	4	5
CANDU Nuclear Units											
	200	12	10	8	8	8	68.0	73.9	79.2	81.0	81.0
	500	12	10	8	8	8	68.0	73.9	79.2	80.1	80.1
	850	14	10	10	10	10	66.3	73.1	75.7	77.4	77.4
	1200	14	10	10	10	10	59.3	68.1	71.4	73.1	74.8
Fossil Steam Units											
Lignite	150/200	12	10	8	8	8	69.7	74.0	78.3	80.1	80.1
Lignite	300	12	10	10	10	10	69.7	74.0	76.5	78.3	78.3
Bituminous Coal, or Oil	500	15	12	10	10	10	67.2	73.9	77.4	79.1	79.1
	750	15	12	10	10	10	64.7	70.6	74.0	76.5	76.5
	1000/1200	15	12	10	10	10	61.6	67.2	70.6	74.8	74.8
Combustion Turbine Units		10	10	10	10	10	76.5	76.5	76.5	76.5	76.5
Hydraulic Units		4	4	4	4	4	95.5	95.5	95.5	95.5	95.5

NOTE: Forecasts are for units having major components supplied by manufacturers of most reliable equipment. With less reliable components, an extra 3% and 1% should be added to the AFOR and MOF.

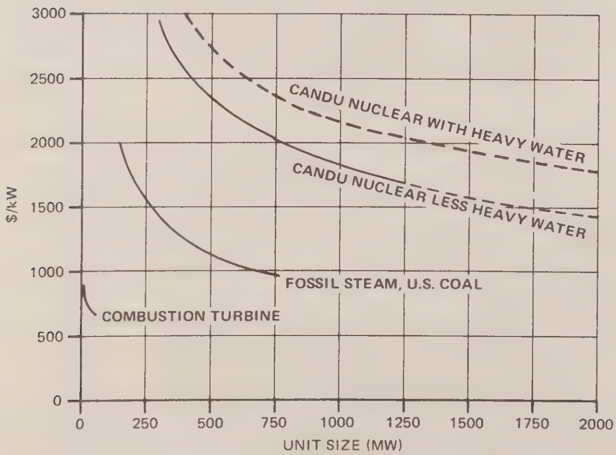
Figure 6.1-6
Thermal Generation, Estimated Capital Cost Per Kilowatt Sent—Out from the Generating Station (4—Unit Plants)



A
Capital Cost Per Kilowatt
Constant January 1976 $



B
Capital Cost Per Kilowatt
1985 In Service
Escalation Included



C
Capital Cost Per Kilowatt
1995 In Service
Escalation Included

Estimated capital costs include net cost of commissioning and for nuclear units include cost of half initial fuel.

FIGURE 6.1-7

Thermal Generation, Estimated Annual Operations & Maintenance Costs in Dollars Per Kilowatt Sent-Out at the Generating Station

These data apply for 4-unit generating stations and do not include the cost of fuel consumed in the stations. Costs are for 1976.

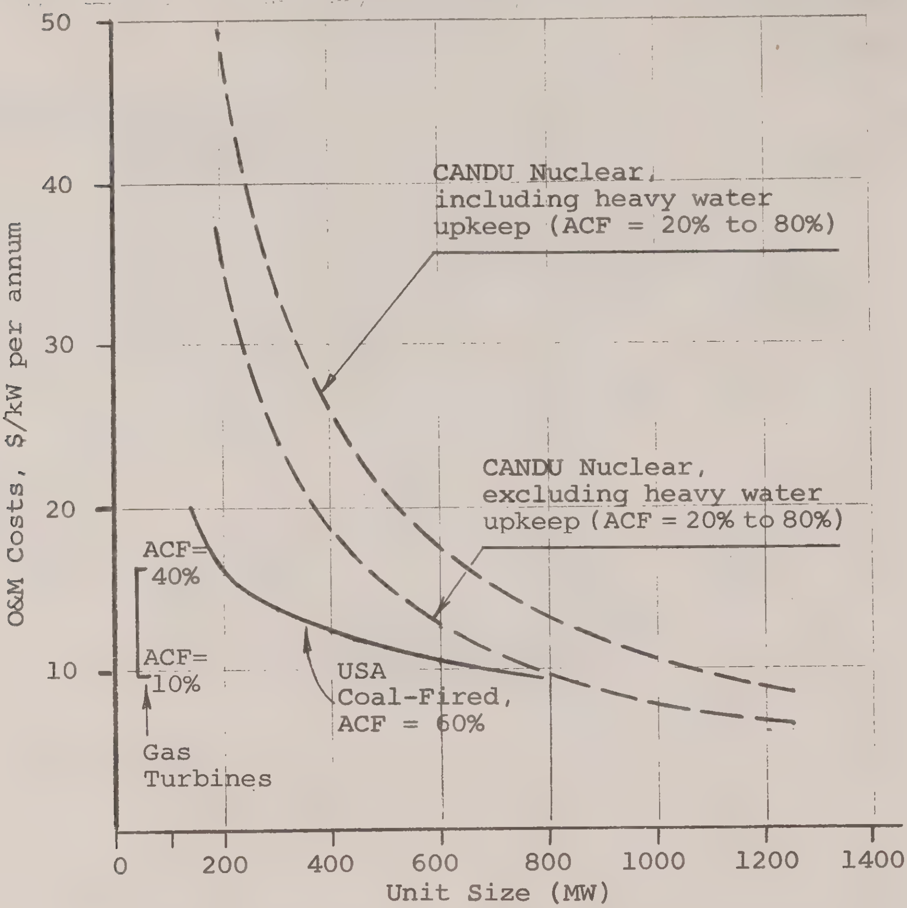
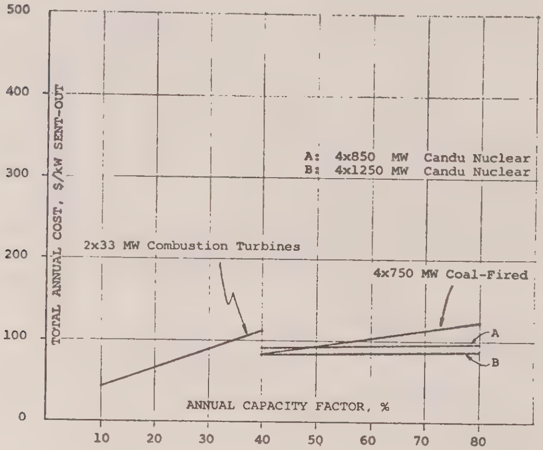


FIGURE 6.1-7

FIGURE 6.1-8

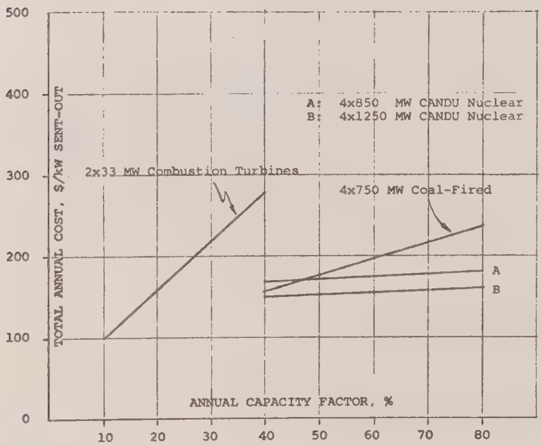
Thermal Generation, Estimated Total Annual Costs
Per Kilowatt Sent-Out From the Generating Stations

I. Interest 10%, Sinking Fund Depreciation, No Statutory Sinking Fund



1976

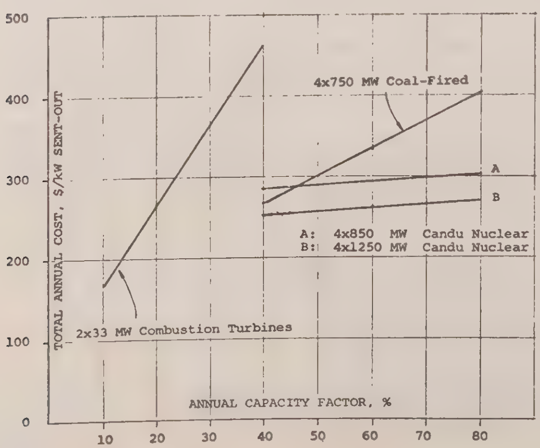
All costs in 1976 dollars.



1985

First unit in service in 1985.

Operation, Maintenance and Fuel Costs escalated to 1985.



1995

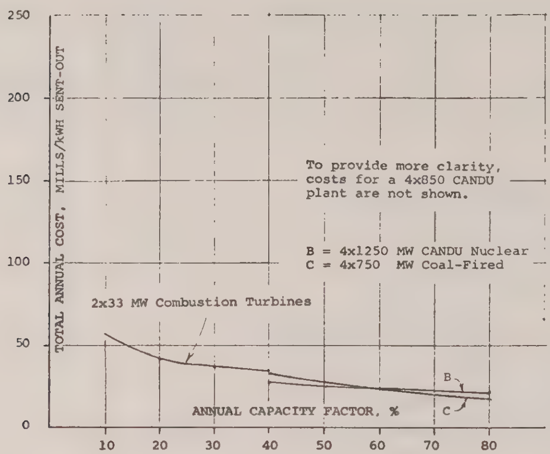
Station in service in 1995.

Operation, Maintenance and Fuel Costs escalated to 1995.

FIGURE 6.1-11

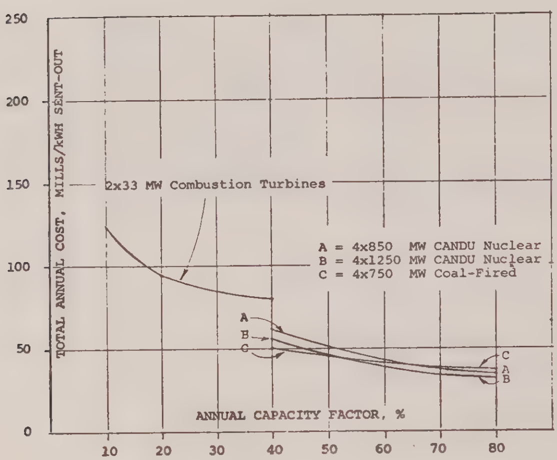
Thermal Generation, Estimated Total Annual Costs
Per Kilowatthour Sent-Out From the Generating Stations

II. Interest 10%, Straight Line Depreciation, + Statutory Sinking Fund



1976

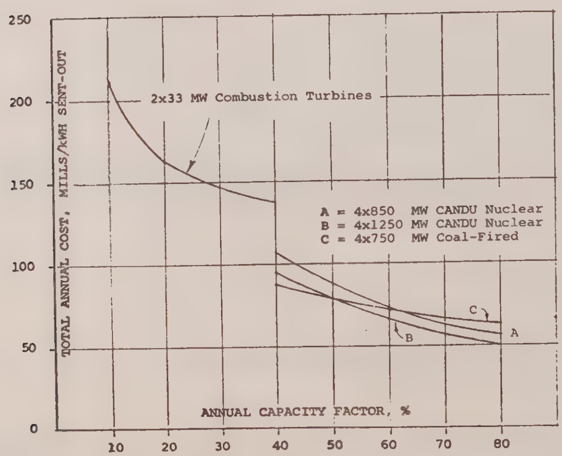
All costs in 1976 dollars.



1985

First unit in service in 1985.

Operation, Maintenance and Fuel Costs escalated to 1985.



1995

Station in service in 1995.

Operation, Maintenance and Fuel Costs escalated to 1995.

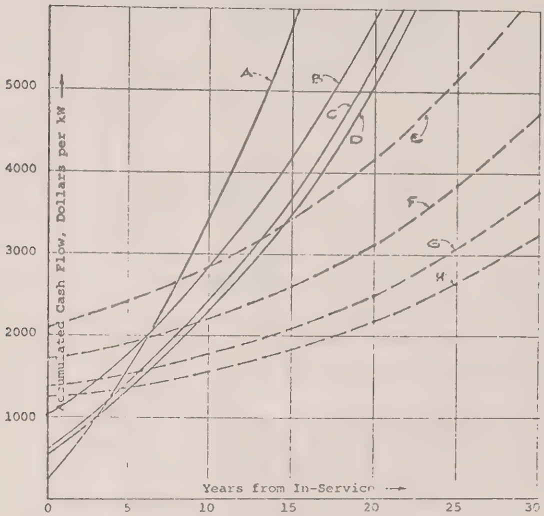
FIGURE 6.1-11

FIGURE 6.1-12

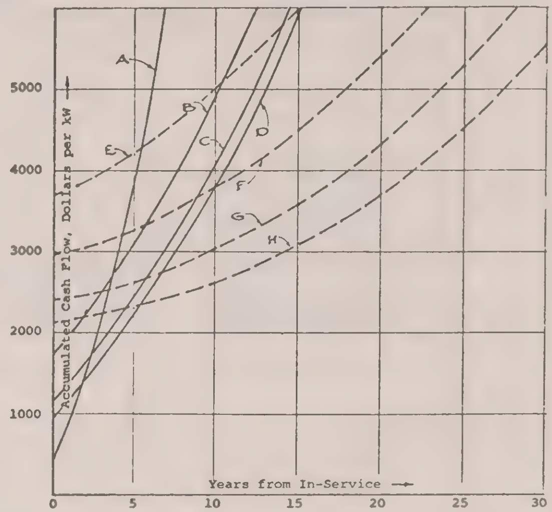
Thermal Generation, Accumulated Total Cash Outflow Per Kilowatt Sent-Out at the Generating Station (Annual Capacity Factor: 60%)

I - Undiscounted Dollars

(First Unit In-Service: 1985)

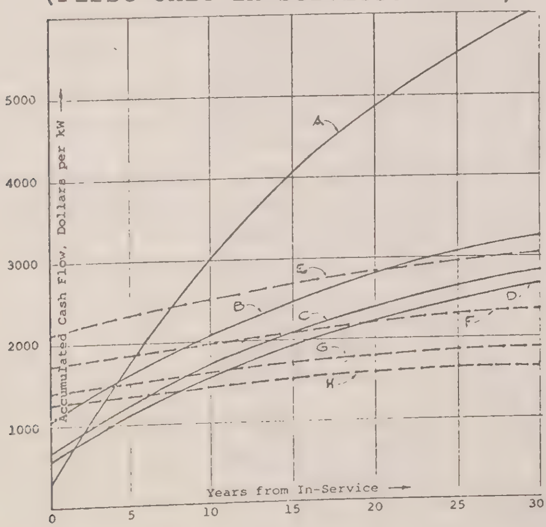


(First Unit In-Service: 1995)

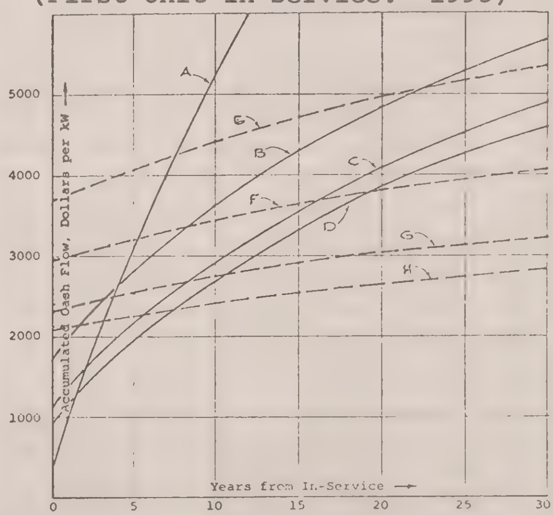


II - Discounted Dollars at 10% Per Annum

Discounted to 1985
(First Unit In-Service: 1985)



Discounted to 1995
(First Unit In-Service: 1995)

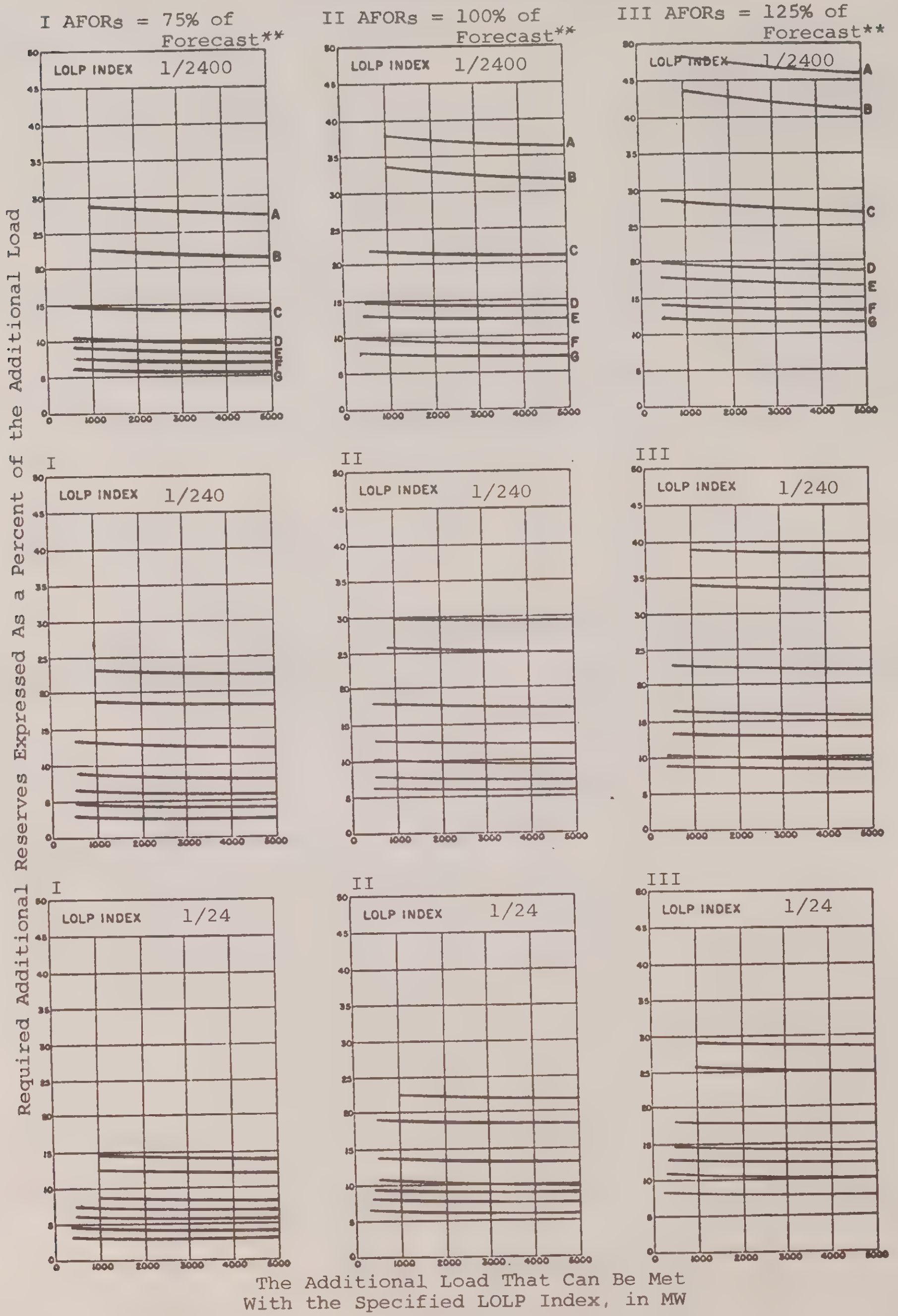


LEGEND:
- A = 2 x 33 MW Combustion Turbines
- B = 4 x 200 MW Fossil (US Coal)
- C = 4 x 500 MW Fossil (US Coal)
- D = 4 x 750 MW Fossil (US Coal)
- E = 4 x 300 MW CANDU Nuclear
- F = 4 x 500 MW CANDU Nuclear
- G = 4 x 850 MW CANDU Nuclear
- H = 4 x 1250 MW CANDU Nuclear

FIGURE 6.1-12

FIGURE 6.1-13

The Required Additional Generating Reserves, Expressed As a % of the Additional Load That Can Be Supplied With a Specified Target Reliability, for the Addition* of a Series of Identical Generating Units



Unit Additions	Size in MW	Type	Forecast** AFOR %
A	1250	N	12
	1200	F	12
B	1000	F	12
C	850	N	10
	750	F	10
D	600	N	9
	500	N	9
E	500	F	8
F	300	N	8
G	200	N	8

* Additional units added to Ontario Hydro's existing and committed system as of January 1976, plus Bruce B GS and Darlington GS.

** 1975 forecast of mature AFORs.

FIGURE 6.1-13

FIGURE 6.1-14

Estimates of the Required Percent Reserve Capacity Associated With a Major Series of Additions of Identical Units*

	Type of Units MW	Type	Forecast** AFOR, %	Required Reserve As % of Load: AFORs 75% of Forecast	AFORs 100% of Forecast	AFORs 125% of Forecast
I Loss of Load Probability 1/2400						
A.	1250 1200	Nuclear Fossil	12) 12)	23	32	42
B.	1000	Fossil	12	20	27	36
C.	850 750	Nuclear Fossil	10) 10)	14	19	25
D.	600 500	Nuclear Nuclear	9) 9)	10	14	19
E.	500	Fossil	8	8	12	16
F.	300	Nuclear	8	6	10	13
G.	200	Nuclear	8	5	7	10
II Loss of Load Probability 1/240						
A.	1250 1200	Nuclear Fossil	12) 12)	19	26	34
B.	1000	Fossil	12	16	23	30
C.	850 750	Nuclear Fossil	10) 10)	11	16	21
D.	600 500	Nuclear Nuclear	9) 9)	8	12	16
E.	500	Fossil	8	7	10	14
F.	300	Nuclear	8	5	8	12
G.	200	Nuclear	8	4	7	9
III Loss of Load Probability 1/24						
A.	1250 1000	Nuclear Fossil	12) 12)	13	19	25
B.	1000	Fossil	12	12	17	23
C.	850 750	Nuclear Fossil	10) 10)	8	13	17
D.	600 500	Nuclear Nuclear	9) 9)	6	10	13
E.	500	Fossil	8	5	8	11
F.	300	Nuclear	8	4	7	10
G.	200	Nuclear	8	4	6	8

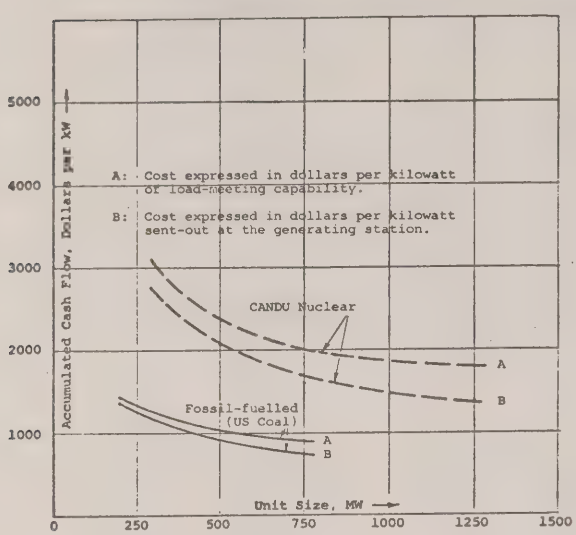
* Additions to Ontario Hydro's existing and committed system as of January 1976, plus Bruce B GS and Darlington GS. The percentages shown correspond to the amounts by which the additions in capacity exceed the additional load that can be supplied with the shown Loss of Load Probability.

** 1975 forecast of mature AFORs.

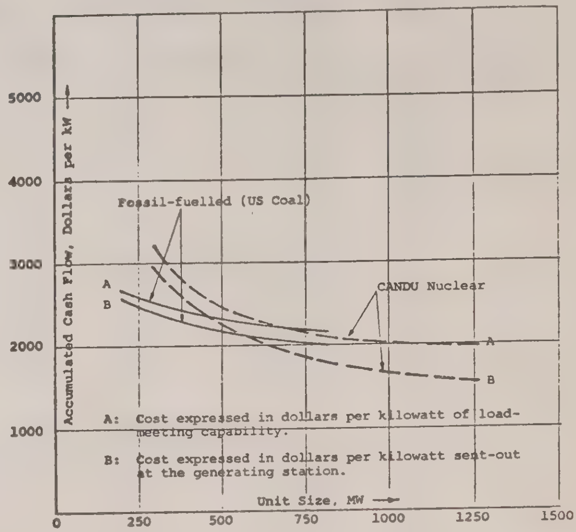
FIGURE 6.1-15

Thermal Generation, Accumulated Cash Outflows at Year 30
For 4-Unit Stations Coming Into Service in 1985,
Discounted to 1985

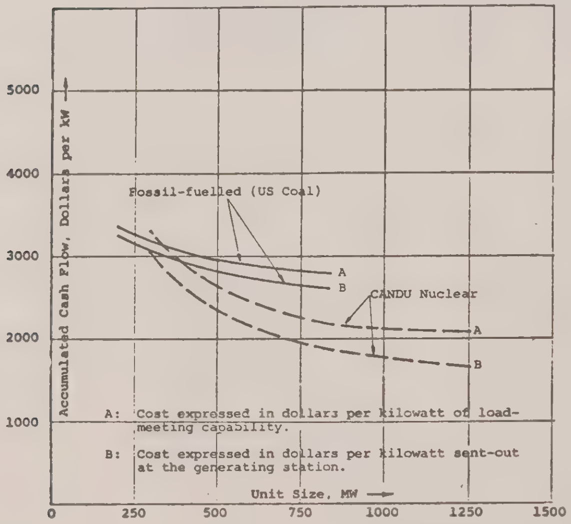
I. Excluding Cost of Fuel



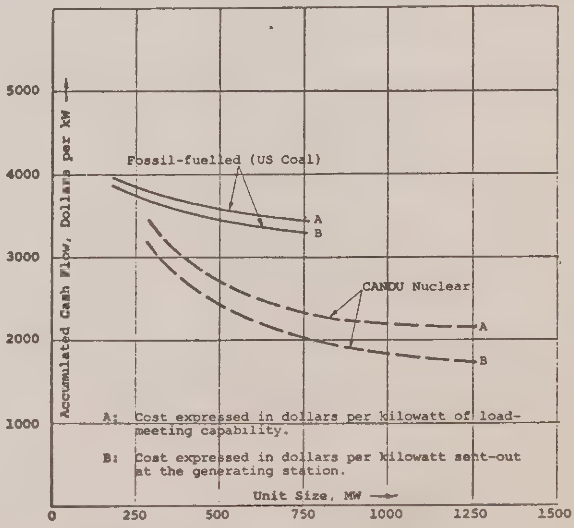
II. Including Cost of Fuel
Annual Capacity Factor: 40%



III. Including Cost of Fuel
Annual Capacity Factor: 60%



IV. Including Cost of Fuel
Annual Capacity Factor: 80%



Notes: 1. Discount factor 10% per annum.
2. LOLP Index 1/2400.
3. AFORs = 100% of Forecast.

FIGURE 6.1-15

FIGURE 6.2-1

Forecast of Ontario Hydro's Annual Fuel Usage 1975-1995

Year	Coal Million U.S. Tons Equivalent	Residual Oil Million Bbl	Natural Gas Bcf	Other Oil Million Bbl	Uranium Mg
1975	7.6	1.3	55.7	0.05	253
1980	16.5	13.7	49.0	0.09	758
1985	17.5	12.9	49.0	0.31	1717
1990	21.6	10.5	49.0	0.38	2917
1995	28.7	10.0	49.0	0.56	4484

Note

Fuel usage refers to the fuel inputs to the power system to meet electrical demands. 1975 and 1980 include both primary and secondary demands. 1985, 1990, and 1995 include primary demand only.

FIGURE 6.2-2

Forecast Distribution of
Ontario Hydro's Annual Energy Production in GWh

Year	Coal	Residual Oil	Natural Gas	Other Oil	Uranium	Hydraulic	Energy Purchases	Total
1975	20,708	709	5,229	15	11,611	34,745	14,874	87,891
1980	45,687	8,165	4,675	30	38,183	34,745	4,100	135,585
1985	49,508	8,535	4,597	115	87,032	34,598	0	184,385
1990	61,442	6,830	4,597	145	147,728	34,598	0	255,340
1995	73,854	6,410	4,597	215	226,972	34,598	0	346,646

Note

Uranium includes that used to produce the energy purchased from AECL's Douglas Point GS, and uranium used to supply steam to the Bruce Heavy Water Production Plants.

FIGURE 6.2-3

Forecast Distribution of
Ontario Hydro's Annual Energy Production in %

Year	Coal	Residual Oil	Natural Gas	Uranium	Hydraulic	Energy Purchases	Total
1975	24	1	6	13	39	17	100
1980	34	6	3	28	26	3	100
1985	27	5	2	47	19	0	100
1990	24	3	2	58	13	0	100
1995	21	2	1	66	10	0	100

Note

Data are based on Figure 6.2-2.

FIGURE 6.2-4

Sources of Energy for Ontario Hydro's Generation of Energy, Expressed as Percentages of Total Ontario Hydro Demand

	Generated in Ontario from						Energy Purchased from		
		Canadian							
Year	Water	Coal	Gas	Uranium	Residual Oil	U.S. Coal	Que.	Man.	U.S.
1920	100	0	0	0	0	0	0	0	0
1925	100						0		
1930	86						14		
1935	72						28		
1940	73						27		
1945	72						28		
1950	72						28		
1955	85	0	0	0	0	2	13	0	0
1960	82	1	0	0	0	4	13	0	1
1965	63	3	0	0	0	19	9	0	6
1970	53	0	0	1	0	33	8	1	4
1975	39	0	6	13	1	24	11	2	4
1980	26	9	3	28	6	25	3	0	0
1985	19	8	2	47	5	19	0	0	0
1990	13	9	2	58	3	15	0	0	0
1995	10	11	1	66	2	11	0	0	0

Notes

1. Figures are rounded off to the nearest whole number.

2. In 1970, domestic sources totalled 63% with foreign imports comprising 33% U.S. coal and 4% U.S. energy.

   In 1975, domestic sources totalled 71% with foreign imports comprising 24% U.S. coal, 1% residual oil and 4% U.S. energy.

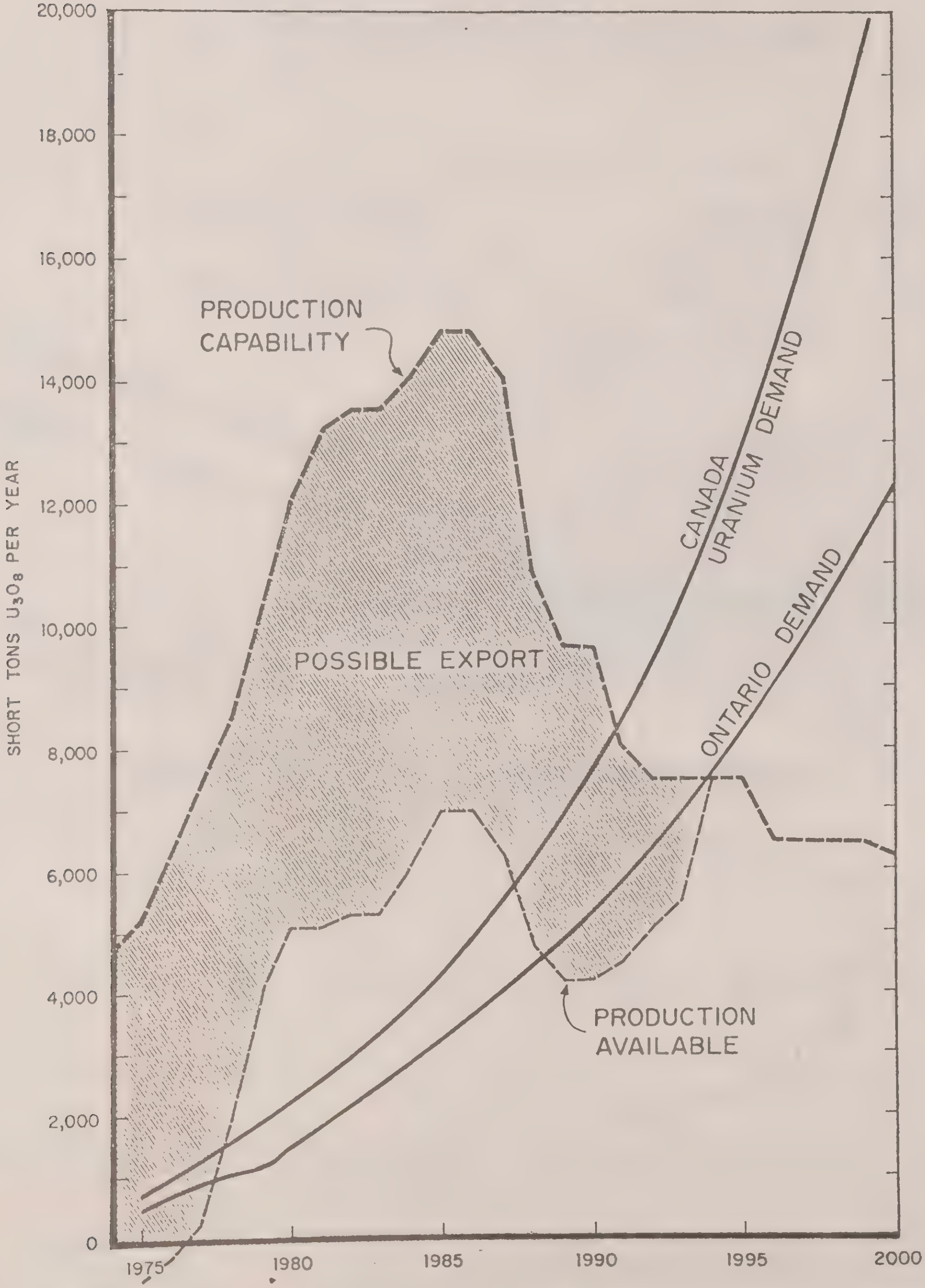
   In 1980, domestic sources are forecast to total about 72% with foreign imports comprising 25% U.S. coal and about 3% residual oil.

   In 1990, domestic sources are forecast to total over 82% with foreign imports comprising 15% U.S. coal and less than 3% residual oil.

FIGURE 6.2-5

CANADA

URANIUM DEMAND AND POTENTIAL SUPPLY FROM KNOWN RESOURCES

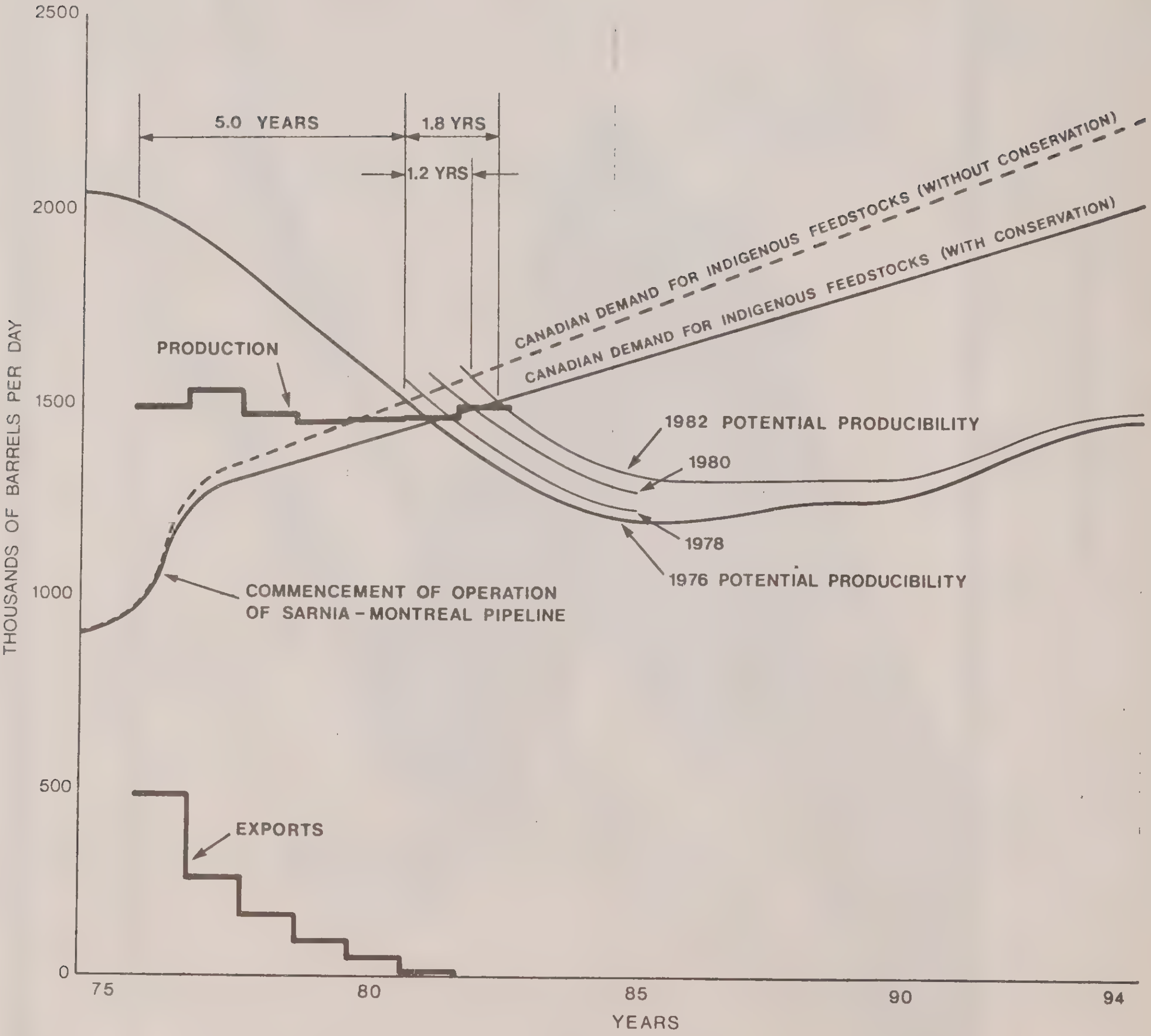


Source: D.S. Robertson & Associates AUGUST/1975

Figure 6.2-6

ESTIMATED CANADIAN PRODUCIBILITY AND

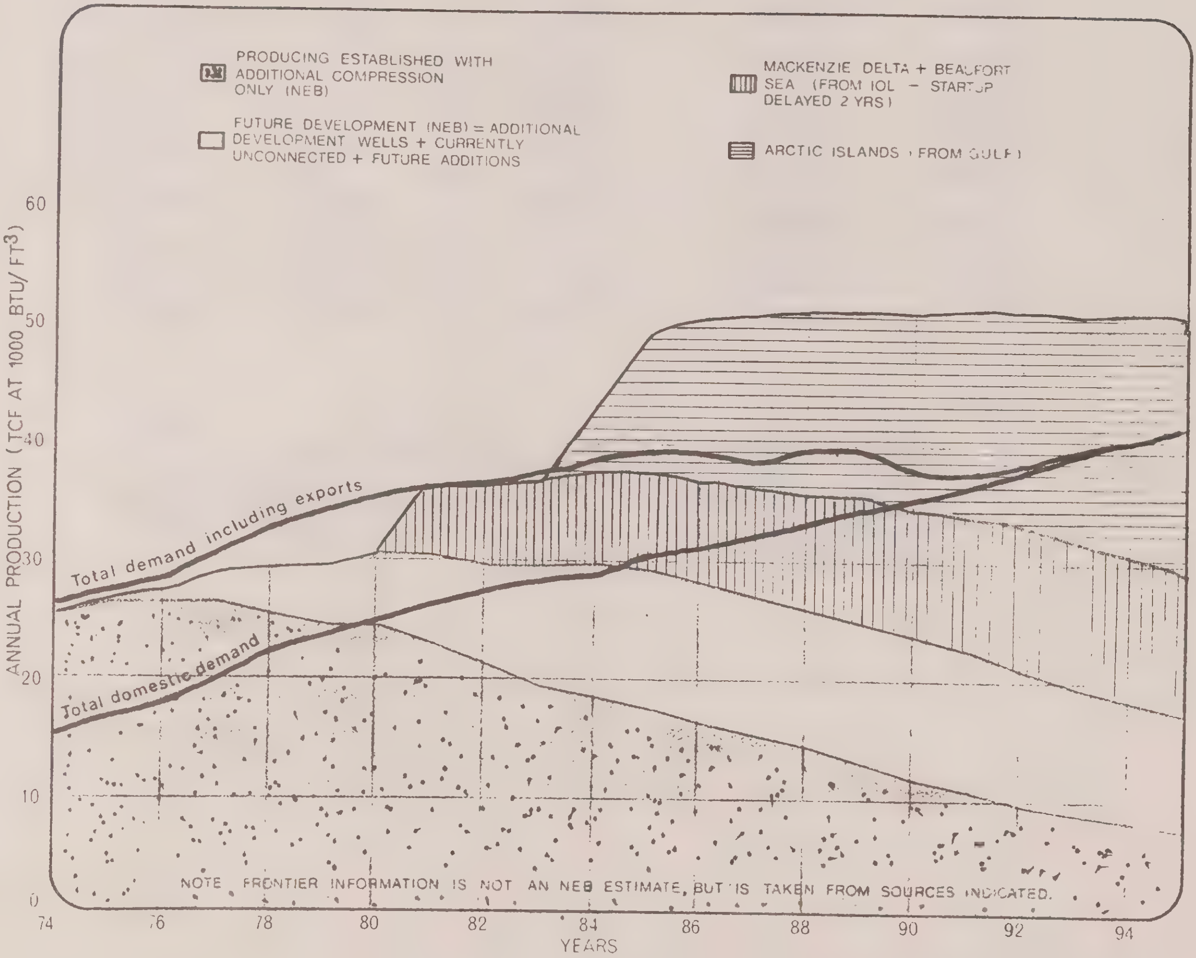
DEMAND FOR CRUDE OIL



Source: Canadian Oil Supply and Requirements, National Energy Board, September 1975

Figure No. 6.2-7

CANADIAN NATURAL GAS SUPPLY AND DEMAND



Source: Canadian Natural Gas, Supply and Requirements, National Energy Board, April 1975.

FIGURE 6.2-7

FIGURE 6.2-8

Projected Usage of Fuels

Year	Thermal Energy Generated GWh	Millions of Tons of Equivalent U.S. Coal			
		Coal	Natural Gas	Residual Oil	Uranium
1970	23,385	8.5	-	-	0.3
1975	38,257	7.6	2.1	0.3	4.2
1980	96,740	16.5	1.9	3.2	13.9
1985	149,787	17.5	1.9	3.0	31.6
1990	220,742	21.7	1.9	2.5	53.7
1995	312,048	28.7	1.9	2.3	82.5

Note

1) Data are based on Figures 6.2-1 and 6.2-2.

2) In the above table, the expected annual usage of the various fossil and nuclear fuels are expressed in equivalent tons of U.S. coal.

FIGURE 6.2-9

Ontario Hydro Fuel Cost Trends
Expressed in Equivalent Thermal Units

Year	Coal	Residual Oil	Natural Gas	Reactor Fuel
1970	112	-	-	23
1975	350	400	300	30
1980	570	1060	820	50
1985	800	1450	1150	80
1990	1050	1900	1500	110
1995	1350	2500	1950	140
2000	1800	3300	2600	200

Note

Coal costs in 1967 have been used as a base index set at 100.

FIGURE 6.2-10

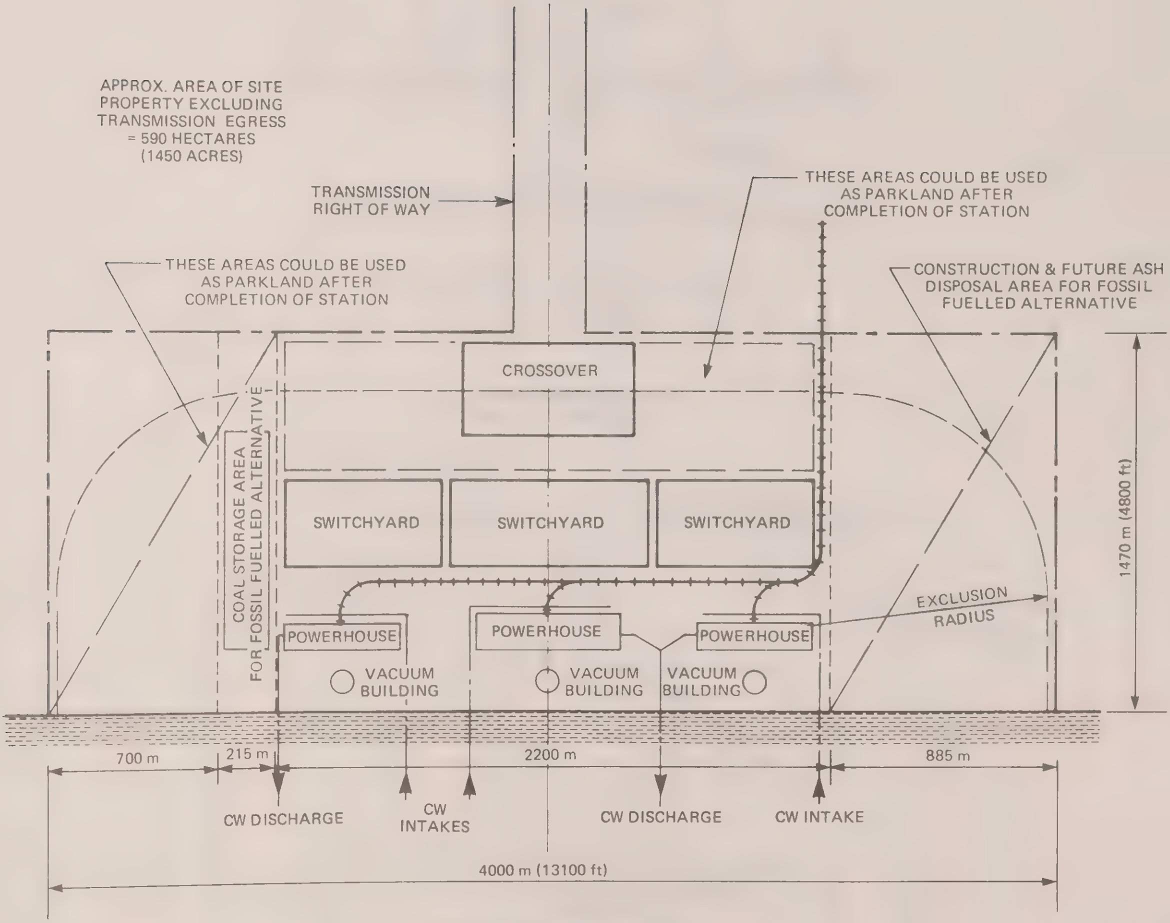
Estimated Sulphur Content of
Ontario Hydro's Fossil Fuels

Year	Equivalent U.S. Coal Consumed Tons x 10^6	Sulphur Content	
		Tons x 10^6	%
1970	8.1	0.202	2.5
1975	10.0	0.200	2.0
1980	21.6	0.342	1.6
1985	22.4	0.345	1.5
1990	26.1	0.394	1.5
1995	32.9	0.428	1.3

Note

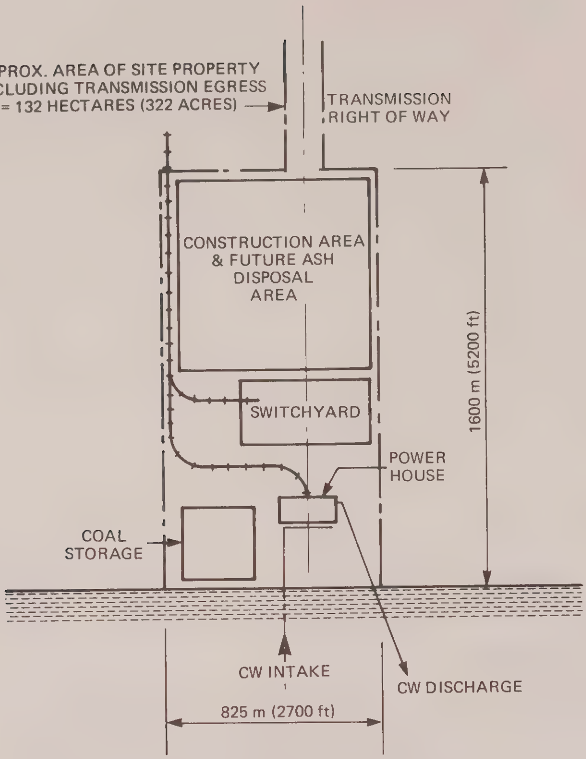
1) Data are based on Figure 6.2-1.

2) Residual oil and natural gas have been converted into equivalent tons of coal using Btu content as a basis.

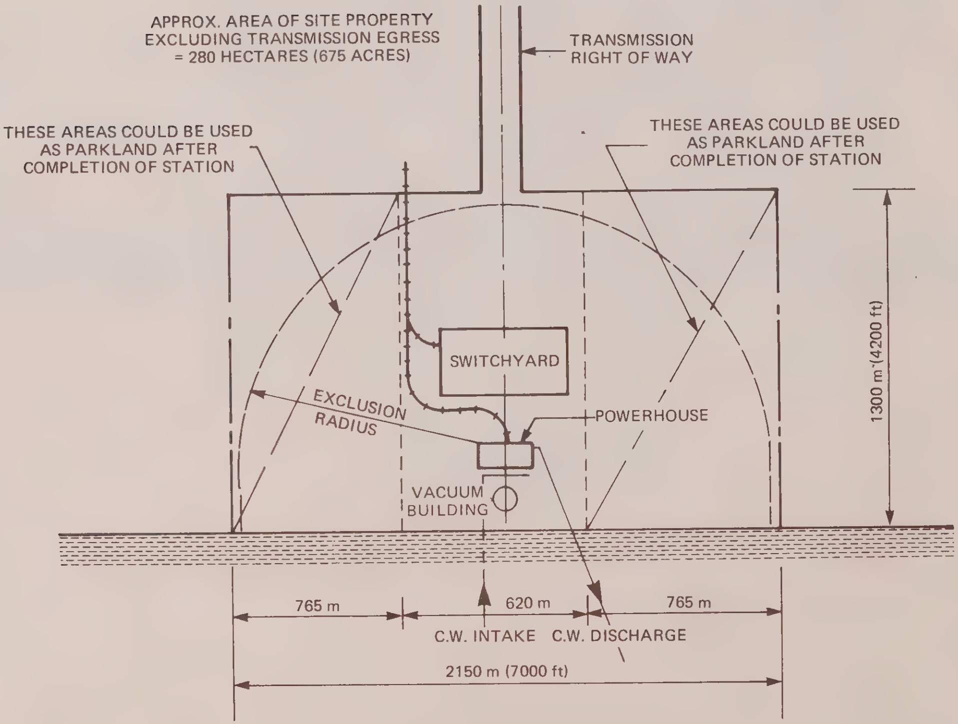


SPACE REQUIREMENTS FOR
TYPICAL ENERGY CENTRE

FIGURE 6.5–1



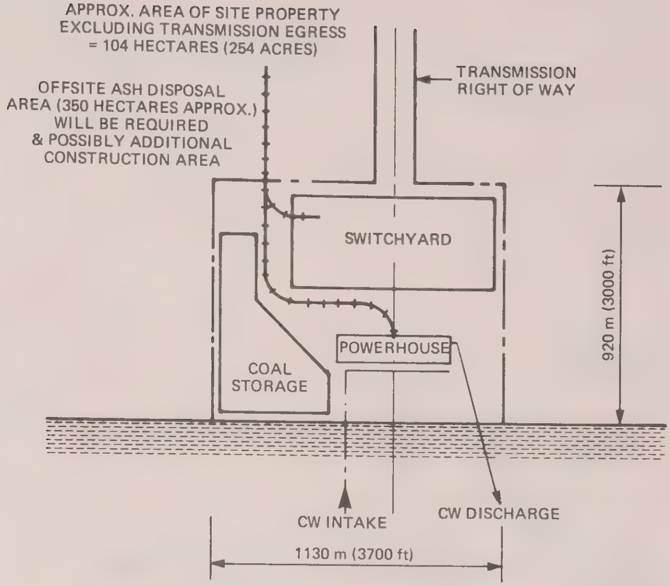
SPACE REQUIREMENTS FOR
4 X 300 MW UNITS (FOSSIL)



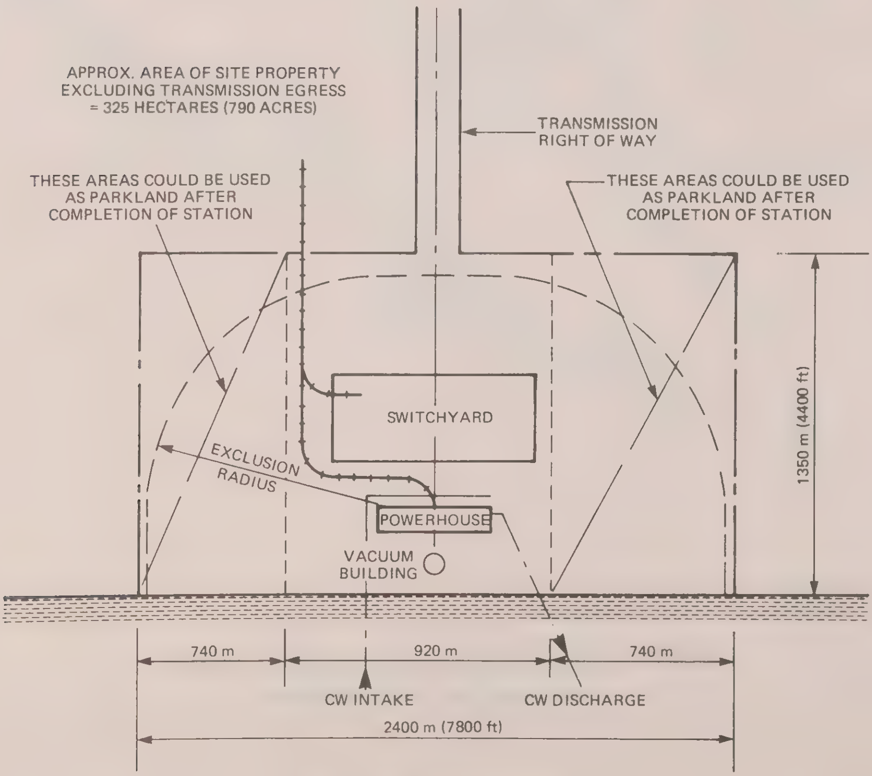
SPACE REQUIREMENTS FOR
4 X 300 MW UNITS (NUCLEAR)

FIGURE 6.5–2

FIGURE 6.5–3



SPACE REQUIREMENTS FOR
4 X 750 MW UNITS (FOSSIL)

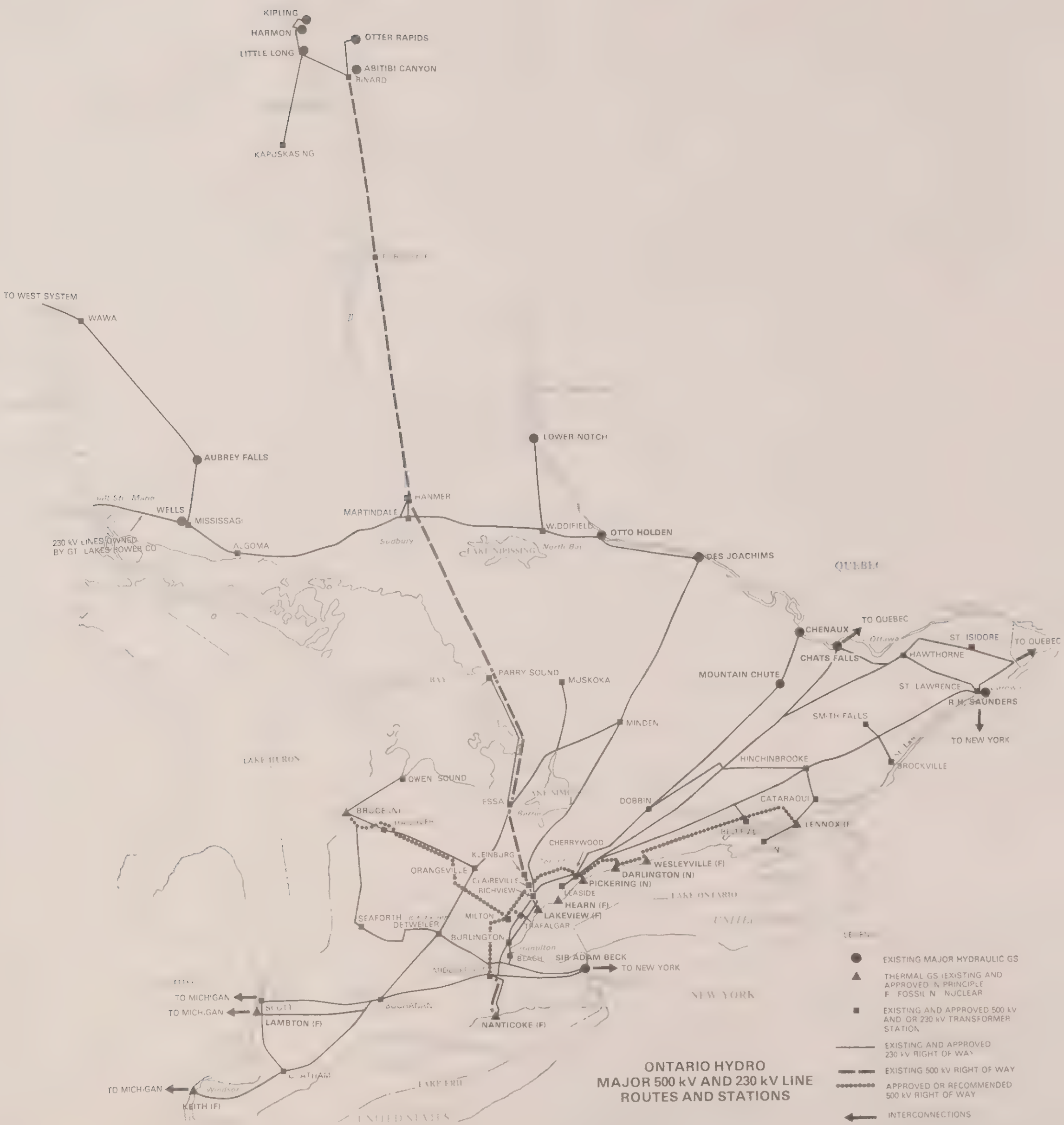


SPACE REQUIREMENTS FOR
4 X 850 MW UNITS (NUCLEAR)

FIGURE 6.5–4
FIGURE 6.5–5

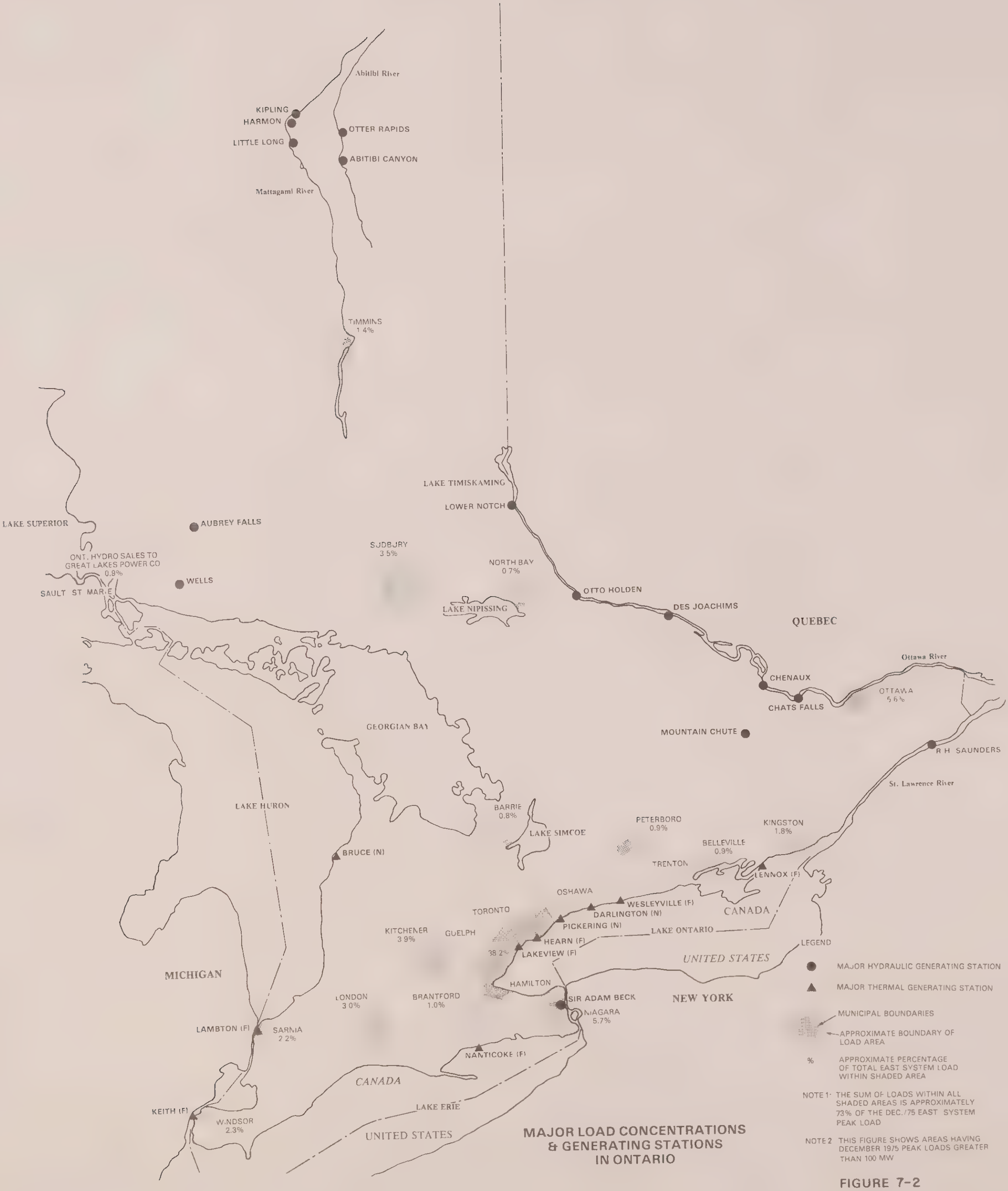
ONTARIO HYDRO EAST SYSTEM STUDY AREAS
FOR GENERATING STATIONS

FIGURE 6.5–6



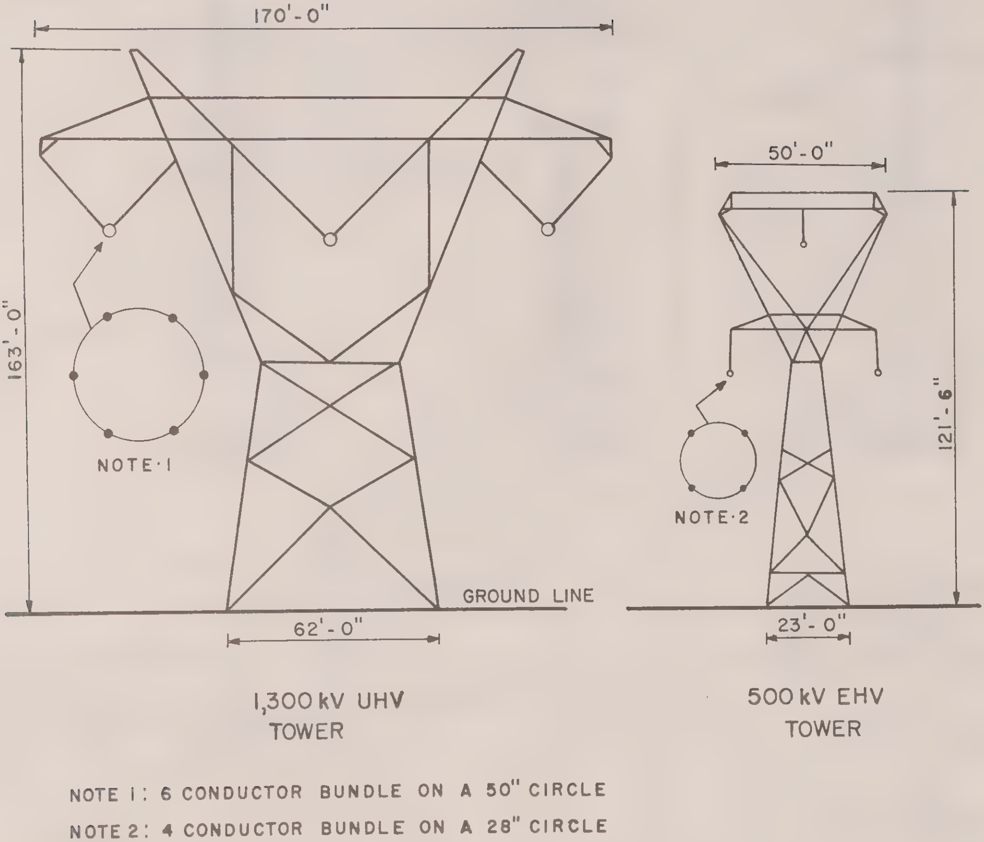
ONTARIO HYDRO
MAJOR 500 kV AND 230 kV LINE
ROUTES AND STATIONS

FIGURE 7–I



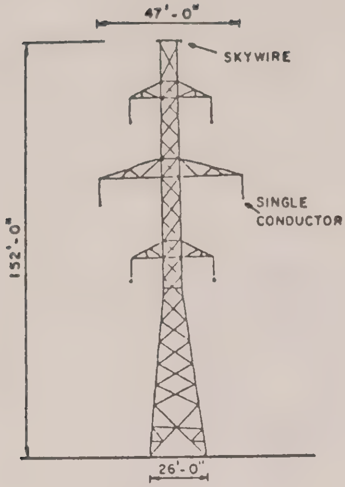
MAJOR LOAD CONCENTRATIONS & GENERATING STATIONS IN ONTARIO

FIGURE 7-2

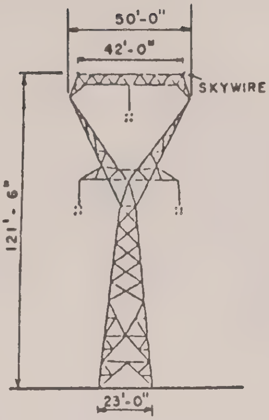


COMPARISON OF 500kV & 1,300kV
TRANSMISSION TOWER STRUCTURES
AND CONDUCTOR CONFIGURATIONS

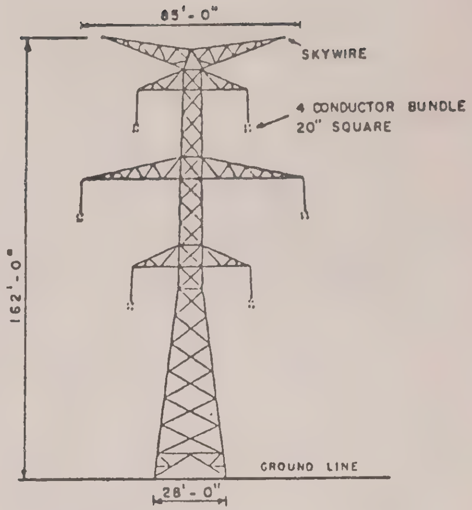
FIGURE 8-1



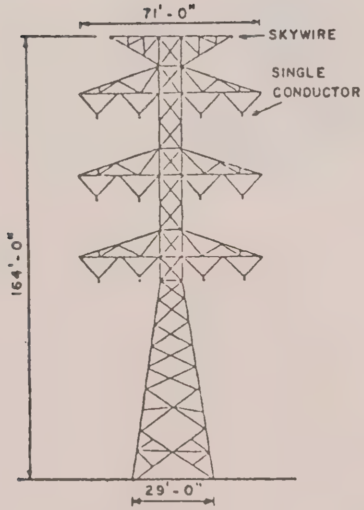
230kV 2-CCT
$ 300,000 / MILE
DIAGRAM 1



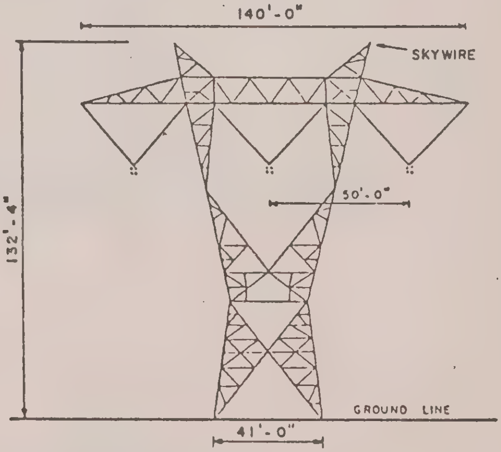
500kV 1-CCT
$ 280,000 / MILE
DIAGRAM 2



500kV 2-CCT
$ 600,000 / MILE
DIAGRAM 3



230kV 4-CCT
$ 630,000/ MILE
DIAGRAM 4



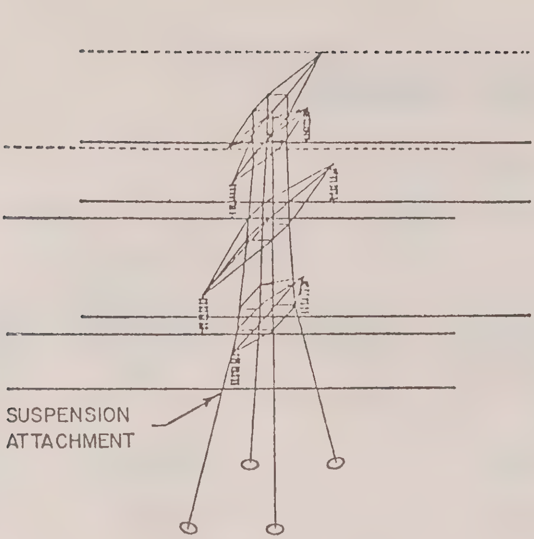
765kV 1-CCT
$ 660,000/MILE
DIAGRAM 5

PER MILE FIGURES DO NOT INCLUDE PROPERTY, LEGAL SURVEY, BUSH CLEARING OR SITE RESTORATION COSTS, AND ARE IN 1976 DOLLARS BASED ON USE OF 58 SUSPENSION, 4 LIGHT ANGLE, 1 MEDIUM ANGLE AND 3 HEAVY ANGLE TOWERS FOR A 10-MILE SECTION.

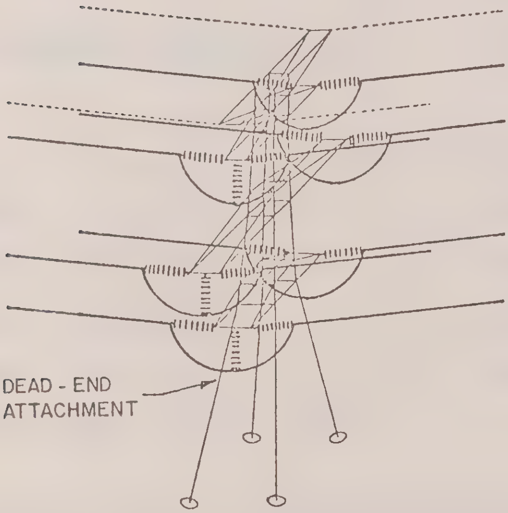
TYPICAL TRANSMISSION SUSPENSION TOWERS

THE HEIGHTS AND GROUND LINE DIMENSIONS ARE MINIMA FOR THE TOWER TYPES SHOWN

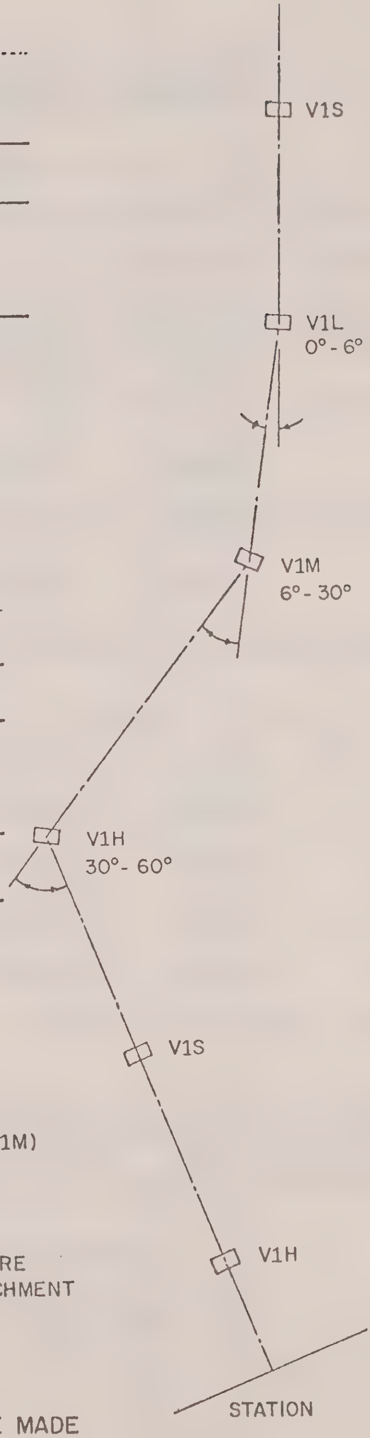
FIGURE 8-2



SUSPENSION (V1S)
LIGHT ANGLE (V1L)



MEDIUM ANGLE OR SEMI-ANCHOR (V1M)
HEAVY ANGLE AND ANCHOR (V1H)



COST OF DEADENDING = $16,000 MORE
PER TOWER THAN SUSPENSION ATTACHMENT

SHOWING HOW LINE ANGLES ARE MADE

FIGURE 8-3

Weights and Installed Cost Comparison
Lattice Vs Pole Structures

230 kV, 2-cct

Lattice Structures			Pole Structures		
Structure Type*	Weight(#) Structure Only	Structure Installed Cost ($)	Structure Type*	Weight(#) Structure Only	Structure Installed Cost($)
S	17,300	25,000	S	34,500	36,000
M	45,000	63,000	M	46,500	63,000
H	58,000	90,000			
Cost per Mile = $300,000			Cost per Mile = $360,000		

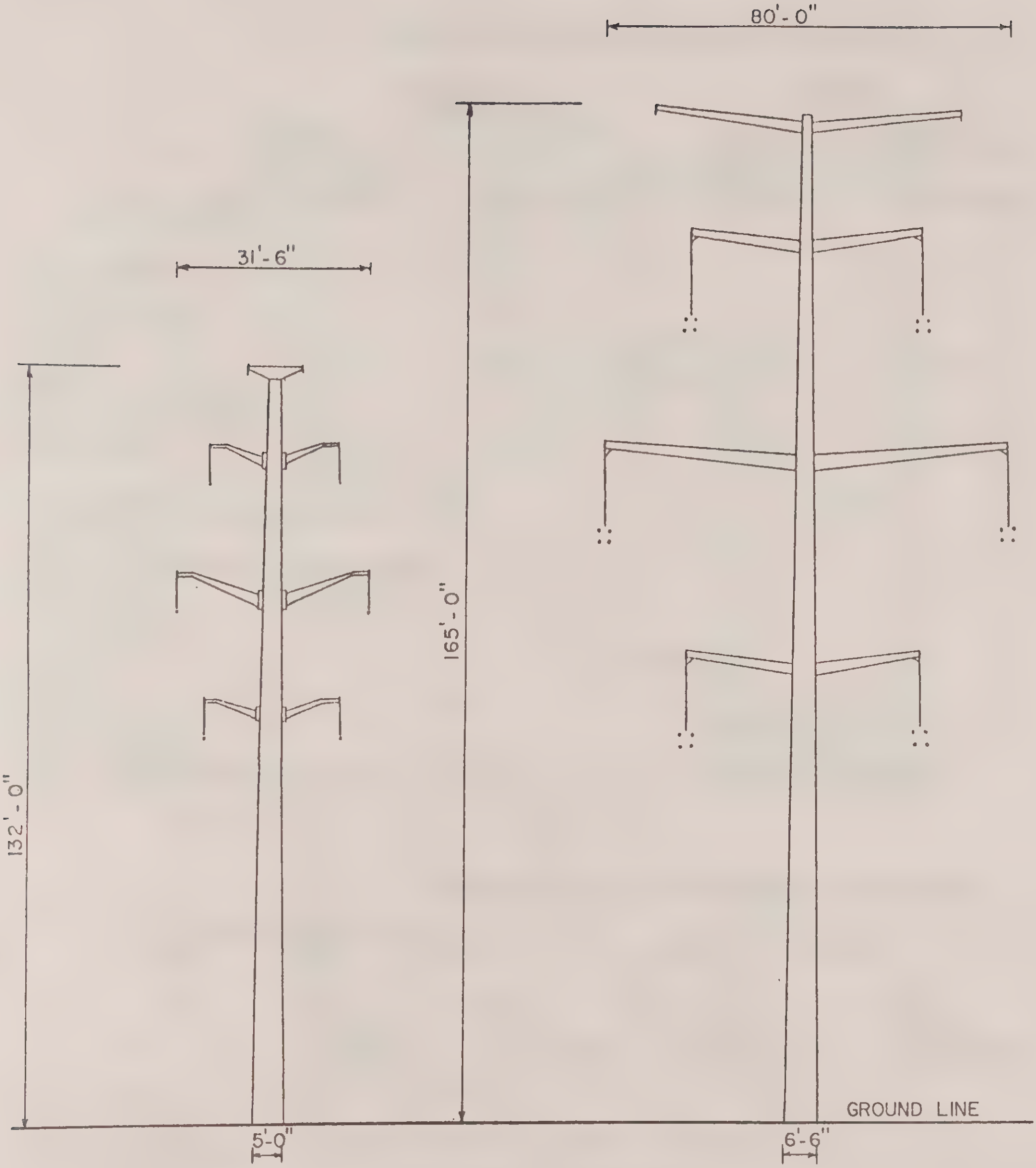
500 kV, 2-cct

S	40,400	55,000	S	98,000	120,000
L	52,800	73,000	L	137,000	158,000
M	108,700	189,000	M	226,000	285,000
H	152,000	250,000	H	230,000	339,000
Cost per Mile = $600,000			Cost per Mile = $1,000,000		

Structure costs are representative of total installed cost of structure with foundation but do not include conductor and stringing costs. Costs are in 1976 dollars.
See note on Figure 8-2 for basis of cost per mile figures.

*S - suspension structure
L - Light Angle structure
M - Medium Angle structure
H - Heavy Angle structure

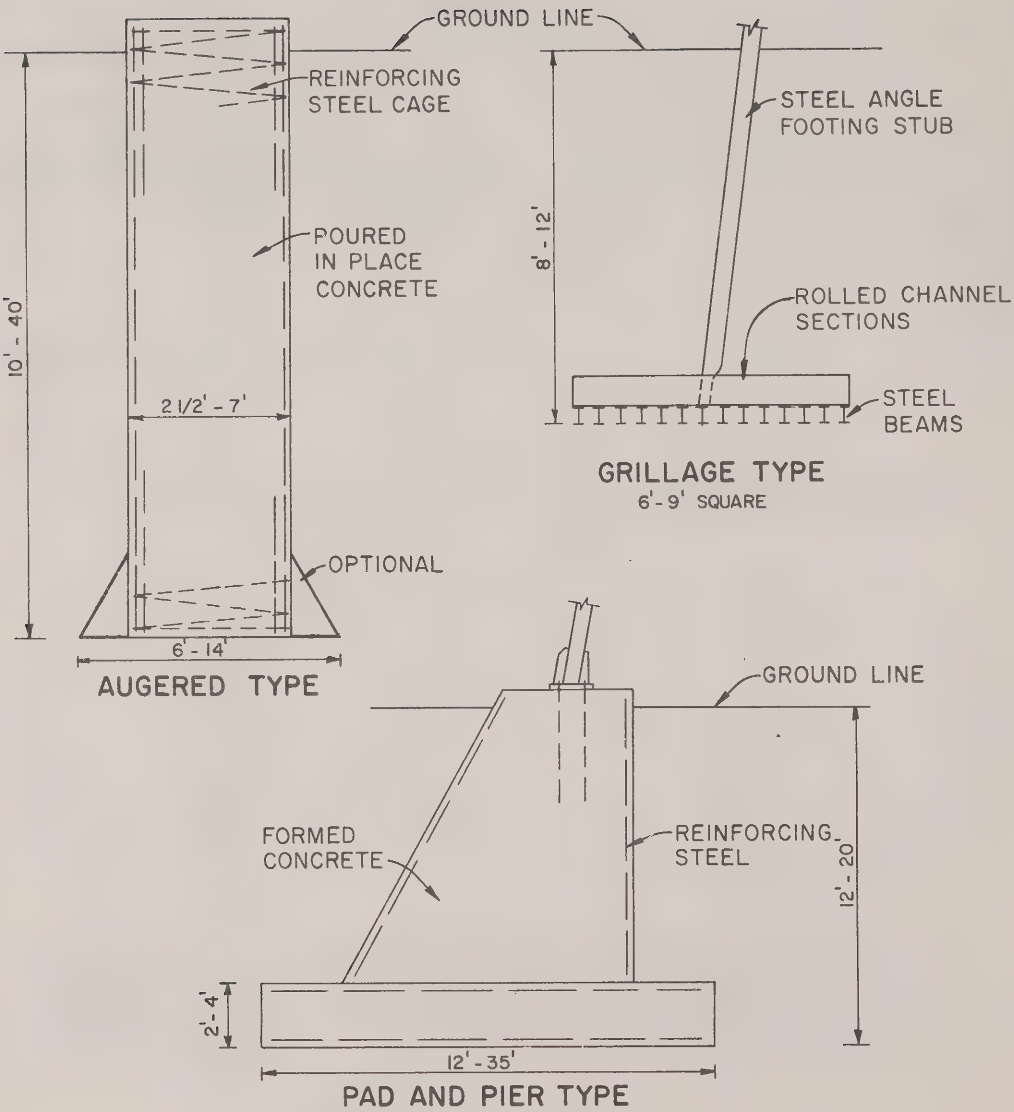
FIGURE 8-4



230kV 2-CCT
SUSPENSION (straight line) POLE STRUCTURE
TYPE X17S
$ 360,000

500kV 2-CCT
SUSPENSION (straight line) POLE STRUCTURE
TYPE V2S
$ 1,000,000

FIGURE 8-5



FOUNDATION TYPES

FIGURE 8-6

Comparison of Vertical Clearances

	230 kV		500 kV	
	CSA require -ment	Ont.Hydro Design Clearance	CSA require -ment	Ont.Hydro Design Clearance
Over land normally traversed by pedestrians only.	15'-0"	18'-0"	20'-7"	25'-0"
Over roads and lanes.	20'-0"	24'-0"	36'-5"	40'-0" *
Over farm lands and lands (other than roads) accessible to vehicles but not normally traversed by large transport trucks.	20'-0"	24'-0"	31'-0"	40'-0"

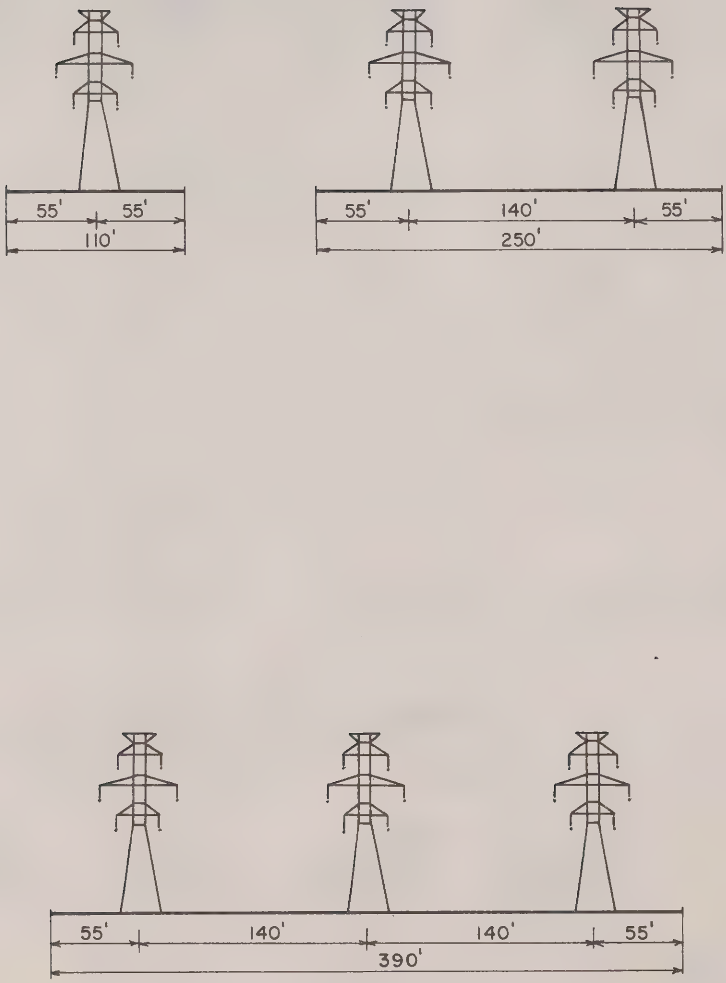
Comparison of Horizontal Clearances

	230 kV		500 kV	
	CSA require -ment	Ont. Hydro Clearance	CSA require -ment	Ont. Hydro Clearance
Horizontal clearance to a readily accessible point or surface of a building	9.2'	11'	14.9'	17'

*Hydro Design Practices Provide for 50'-0" Clearance over Most Travelled Roads

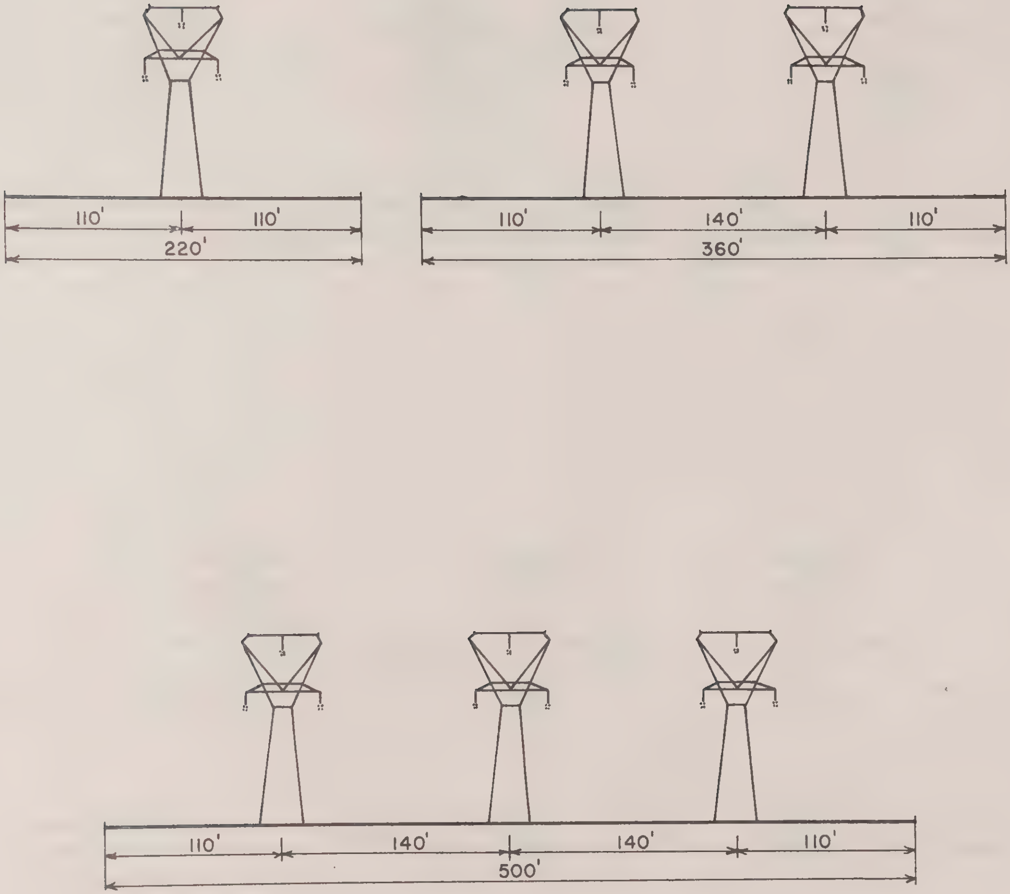
TRANSMISSION LINE CLEARANCES

FIGURE 8-7



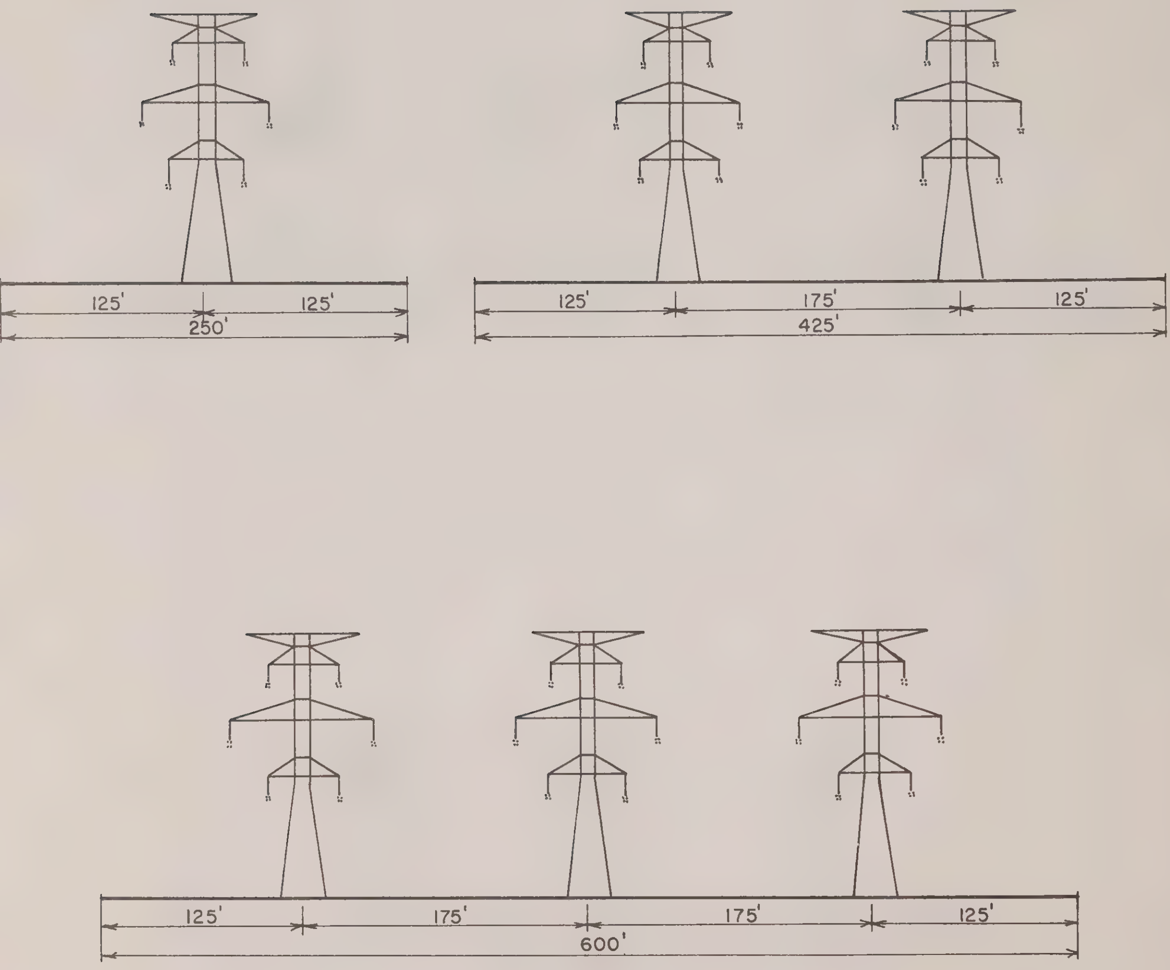
230kV 2-CCT X10 TYPE TOWERS
RIGHT OF WAY WIDTHS

FIGURE 8-8



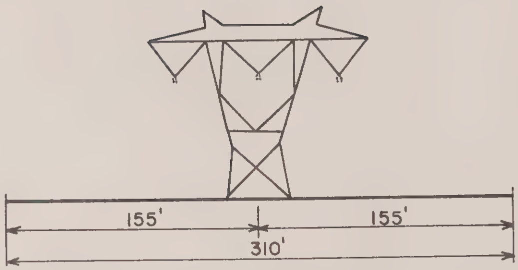
500kV 1-CCT Z11 TYPE TOWERS
RIGHT OF WAY WIDTHS

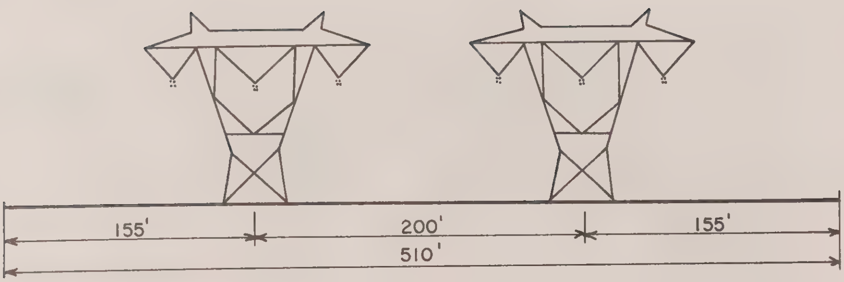
FIGURE 8-9



500kV 2-CCT V1 TYPE TOWERS
RIGHT OF WAY WIDTHS

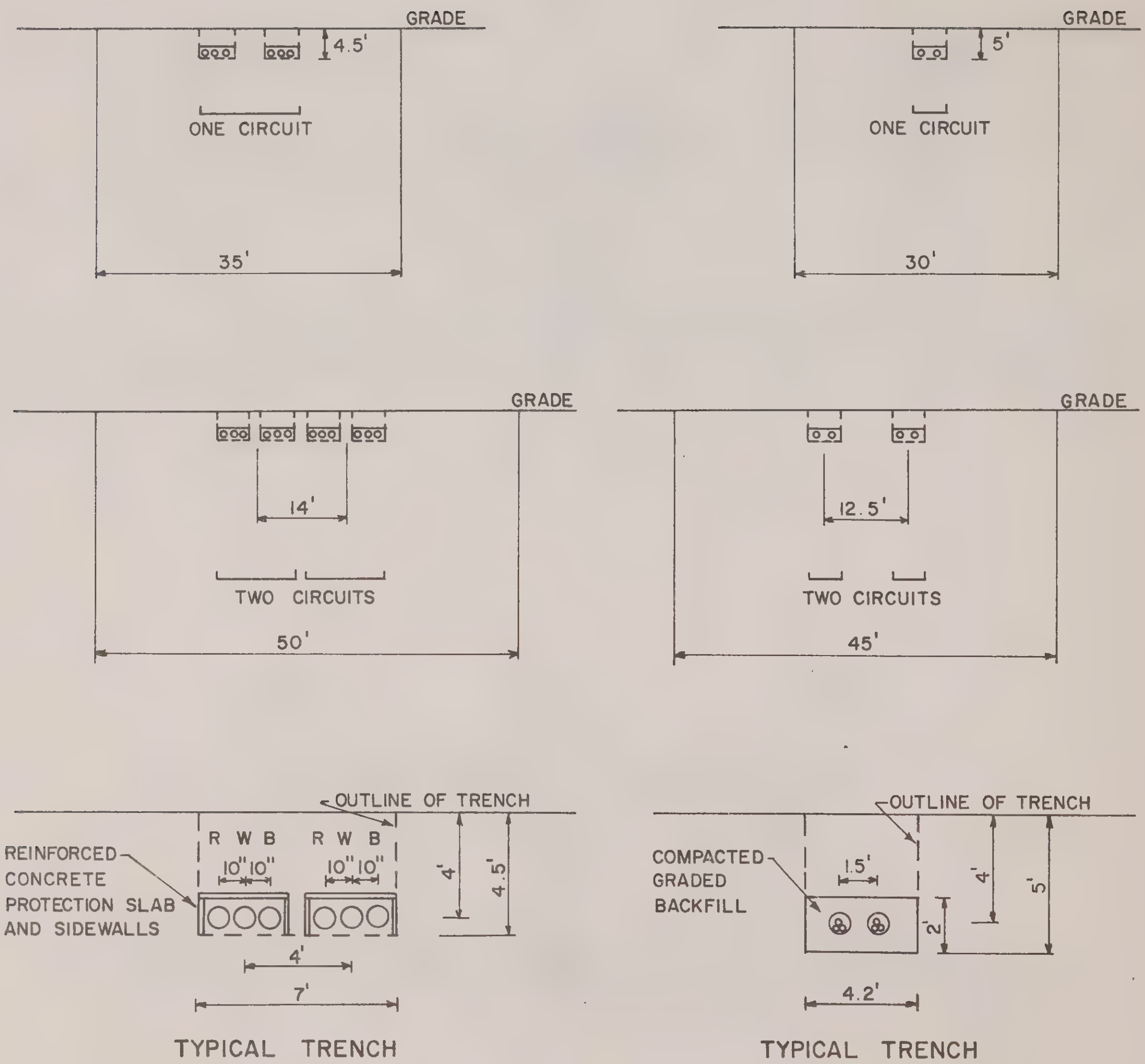
FIGURE 8-10





765kV 1-CCT RIGID TYPE TOWERS
RIGHT OF WAY WIDTHS

FIGURE 8-11



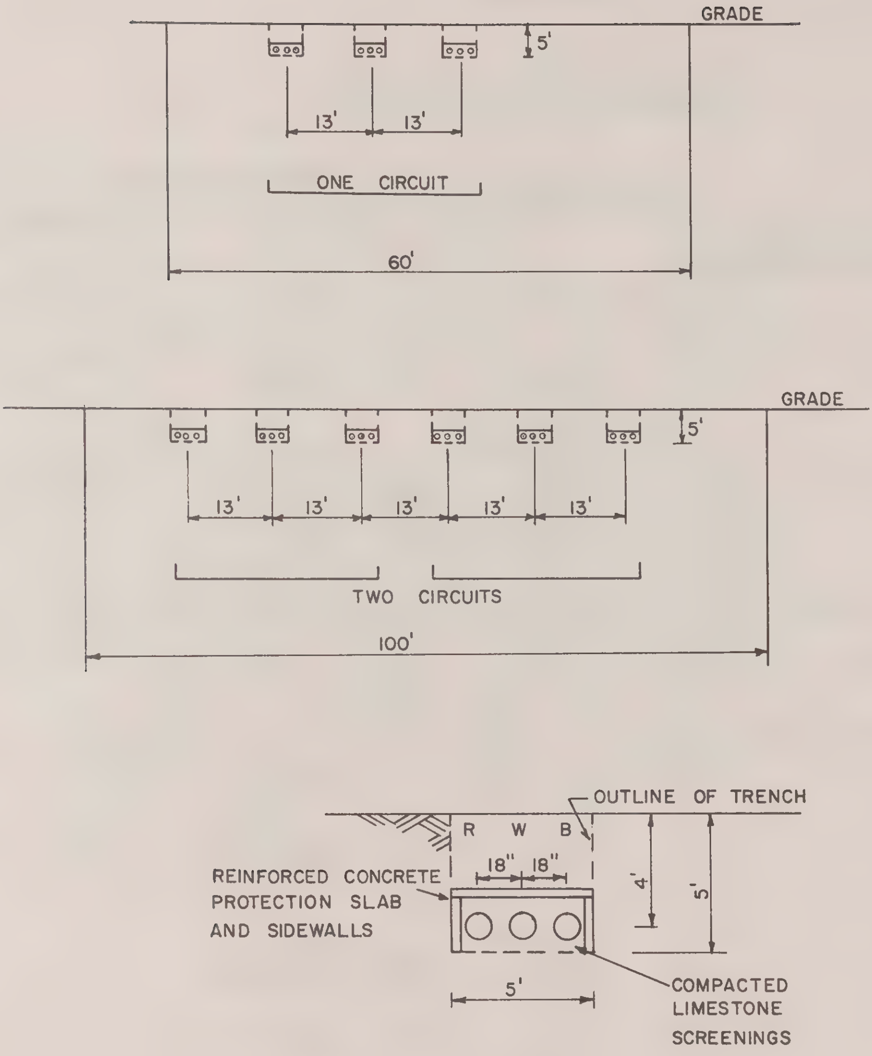
2 x 1500 KCMIL COPPER CONDUCTORS/PHASE
L.P.O.F. CABLE

2x2750 KCMIL COPPER CONDUCTORS/PHASE
H.P.O.F. CABLE

230kV UNDERGROUND CABLE

RIGHT OF WAY WIDTHS

FIGURE 8-12



TYPICAL TRENCH

3 x 3800 KCMIL COPPER CONDUCTORS/ PHASE
L.P.O.F. CABLE

500kV UNDERGROUND CABLE
RIGHT OF WAY WIDTHS

FIGURE 8-13

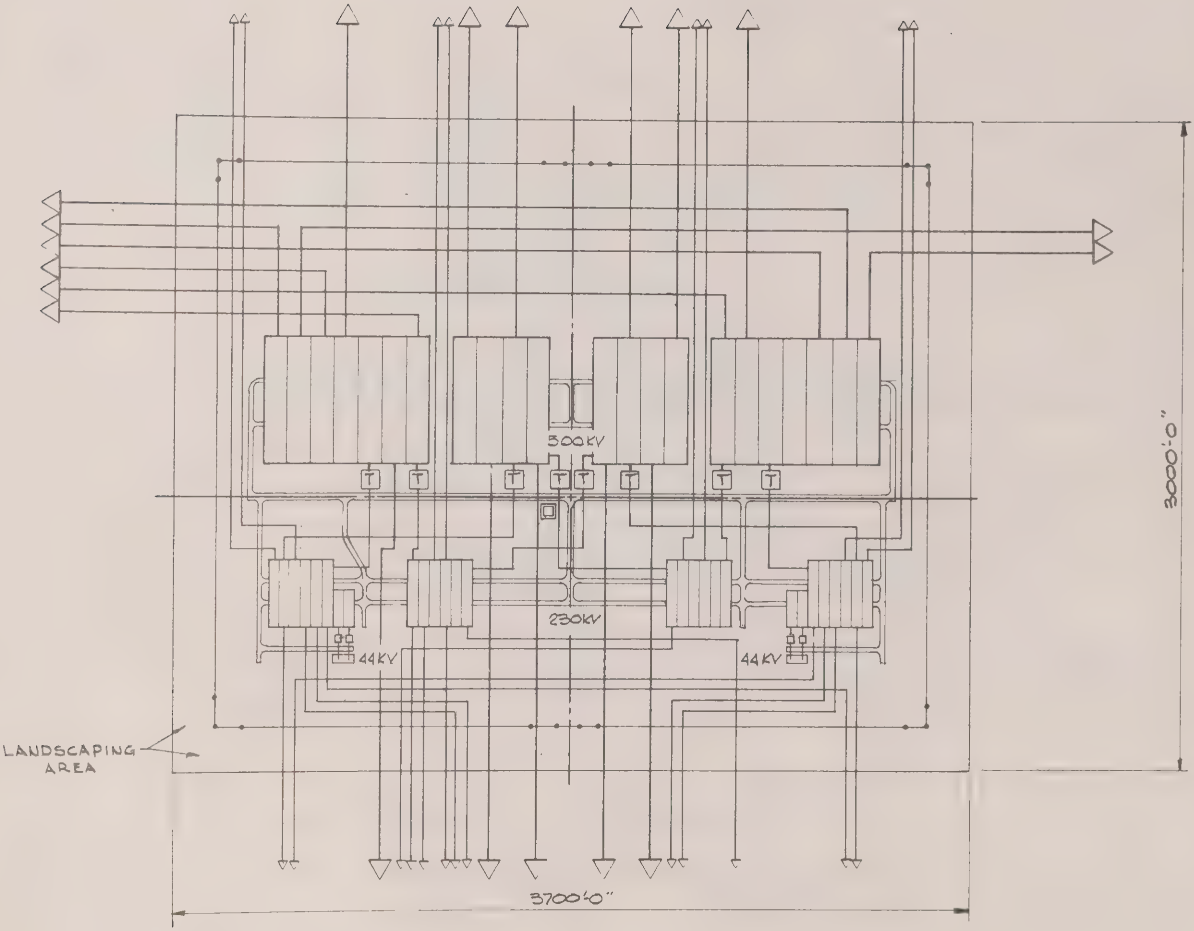
FIGURE 8-14

Comparison of Material Quantities
Overhead Lines vs Underground Cables

Material	Overhead Lines		Underground Cables LPOF		Underground Cables HPOF	
FOR 1-MILE OF 2-CCT 230 KV						
Steel	56	tons (1)		none	233	tons (2)
Copper		none	147	tons (3)	269	tons (3)
Aluminum	32	tons (4)	41	tons (5)		none
Porcelain	4	tons (6)		none		none
Paper		none	59	tons (6)	63	tons (6)
Oil		none	12000	US gals (6)	40000	US gals (6)
Plastic		none	16	tons (7)		none
Brass		none		none	26	tons (8)
Special Backfill		none	3500	cu yds	3000	cu yds
Concrete	171	cu yds	1110	" "		none
Excavation	171	" "	12600	" "	8600	cu yds
FOR 1-MILE OF 2-CCT 500 KV						
Steel	187	tons (1)		none		
Copper		none	557	tons (3)		
Aluminum	57	tons (4)	108	tons (5)		
Porcelain	7	tons (6)		none		
Paper		none	238	tons (6)		
Oil		none	52000	US gals (6)		
Plastic		none	59	tons (7)		
Special Backfill		none	8560	cu yds		
Concrete	544	cu yds	2000	" "		
Excavation	544	" "	24500	" "		

NOTES:
(1) Tower and concrete reinforcing steel
(2) Pipe steel
(3) Electrical conductor
(4) Electrical conductor including reinforcing steel
(5) Cable sheath
(6) Insulating material
(7) Sheath insulation
(8) Protective assembly

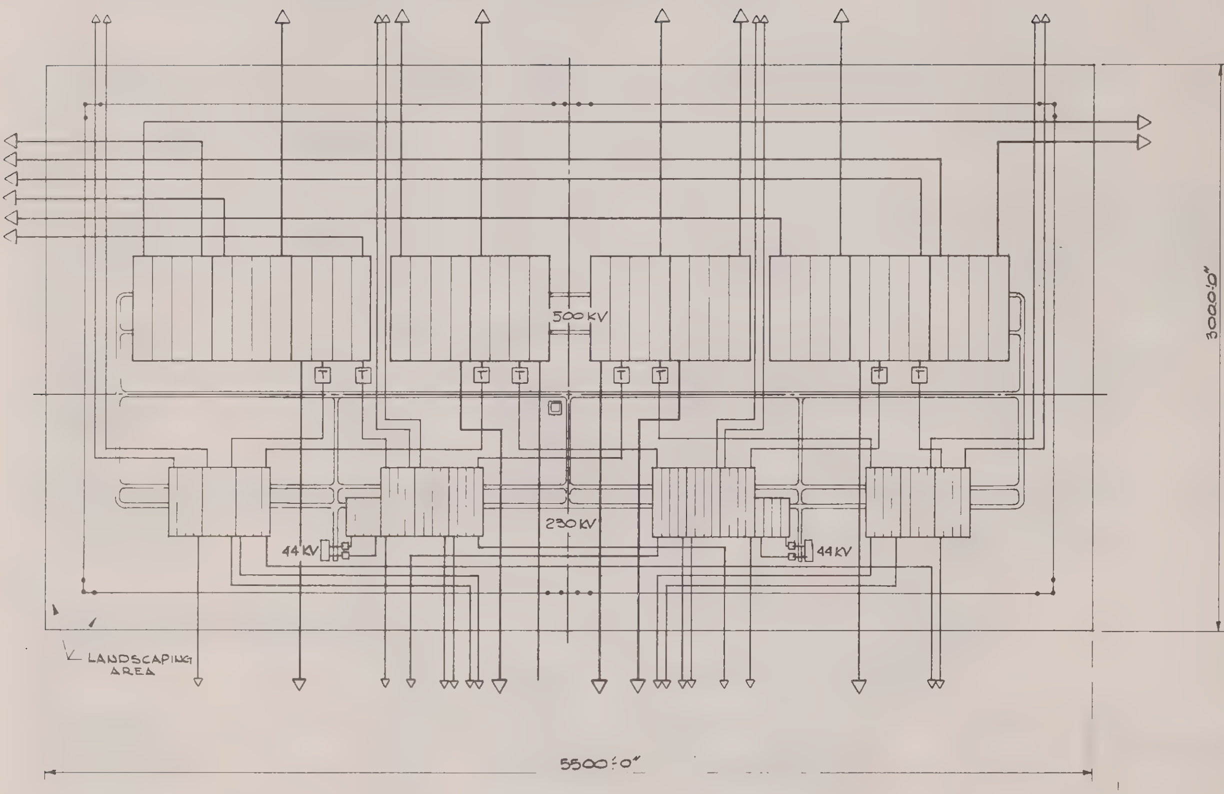
FIGURE 8-14



255 ACRES

SITE LAYOUT - HIGH PROFILE OPEN SWITCHING
WITH TRANSMISSION CONNECTIONS IN OPEN BUS

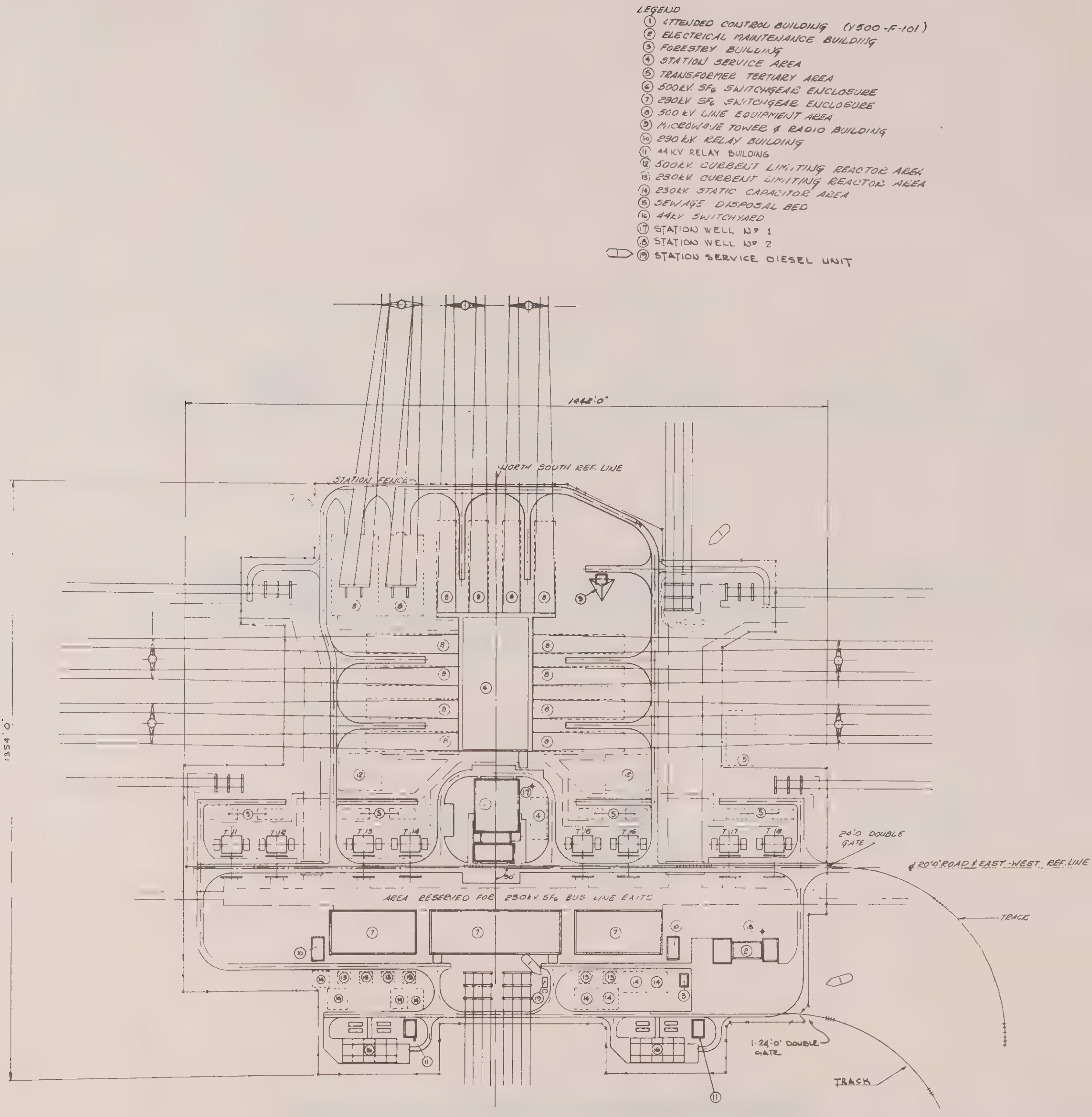
FIGURE 8 - 15



380 ACRES

SITE LAYOUT - LOW PROFILE OPEN SWITCHING
WITH TRANSMISSION CONNECTIONS IN OPEN BUS

FIGURE 8-16



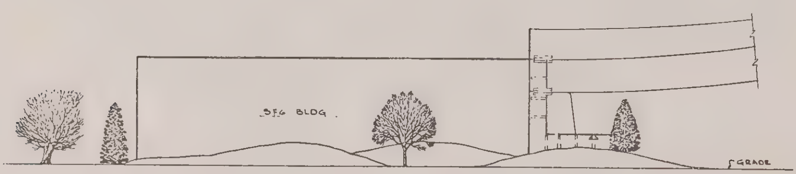
45 ACRES

SITE LAYOUT - GAS INSULATED STATION

FIGURE 8-17

500 KV - HIGH PROFILE

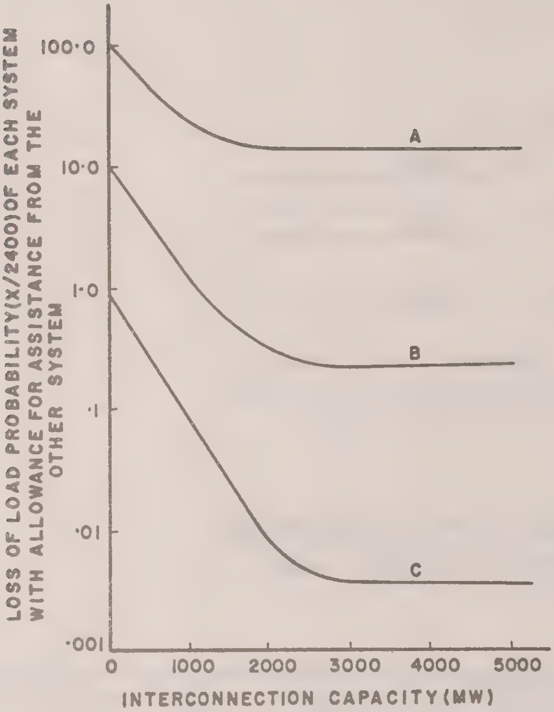
500 KV - LOW PROFILE



500 KV - SF6

TYPICAL ELEVATIONS - THREE 500 KV STATIONS

FIGURE 8-18

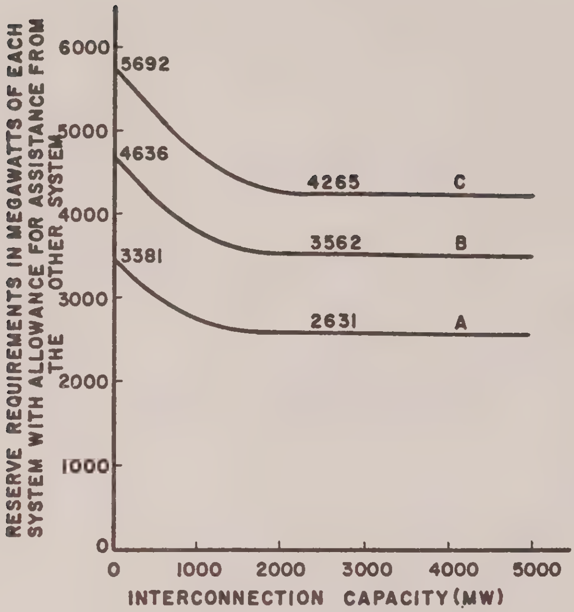


Based on Ontario Hydro East System generation proposed for December 1982 interconnected with identical system. Each system's reserve is held constant at the level which provides the following LOLP with zero interconnection capacity.

Case (a)	100/2400
Case (b)	10/2400
Case (c)	1/2400

ILLUSTRATION OF THE IMPROVEMENT IN THE LOSS OF LOAD PROBABILITY AS A FUNCTION OF THE INTERCONNECTION CAPACITY

FIGURE 9-1

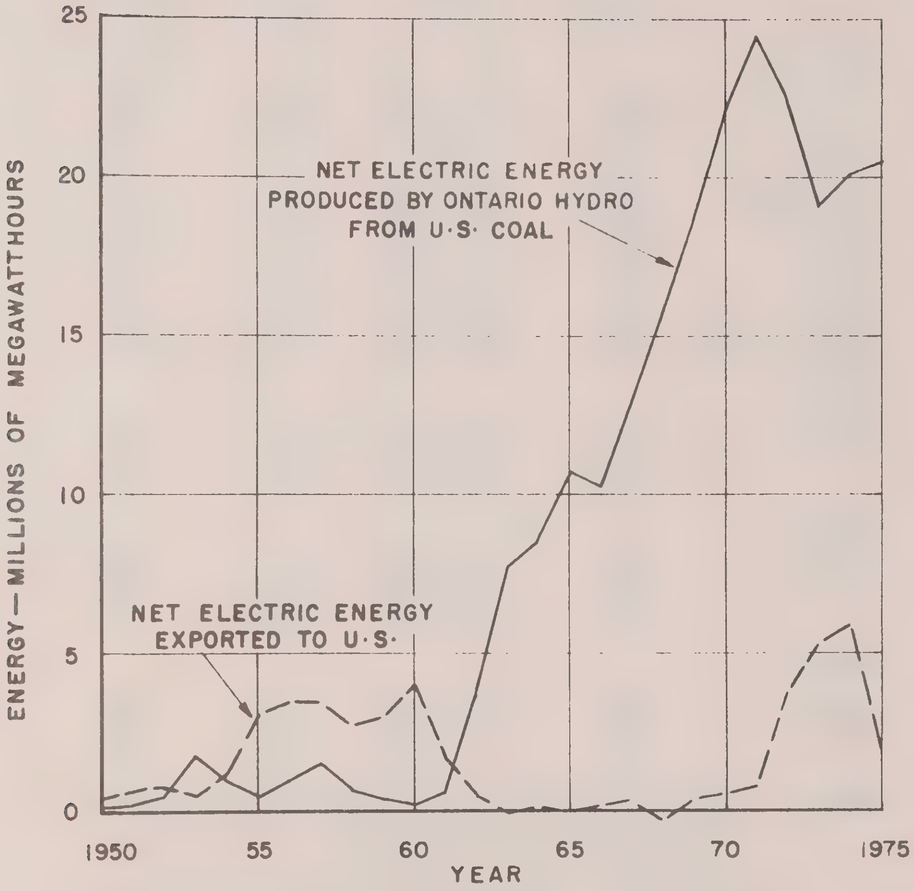


Based on Ontario Hydro East System generation proposed for December 1982 interconnected with identical system. Each system reduces its reserve after interconnection to maintain LOLP at the following level:

Case (a)	100/2400
Case (b)	10/2400
Case (c)	1/2400

ILLUSTRATION OF THE POSSIBLE REDUCTION IN RESERVE REQUIREMENTS AS A FUNCTION OF THE INTERCONNECTION CAPACITY

FIGURE 9-2



ONTARIO HYDRO
ENERGY INTERCHANGES WITH UNITED STATES
(EXCLUDING BORDER ACCOMMODATIONS)

FIGURE 9-3

ONTARIO HYDRO
EXISTING AND PLANNED 60 HZ INTERCONNECTIONS
115 kV AND ABOVE

Location	Designation Col. 1	Date Established (Note 1) Col. 2	Nominal Voltage kV Col. 3	Nominal Winter Capacity MVA (Note 2) Col. 4
QUEBEC				
Beauharnois	B5D	Oct. 1932	230	530
	B31L	Apr. 1941	230	530
Chenaux	X2Y	July 1942	115	65
Val Tetreau	V12 M	Nov. 1928	115	175
Val Tetreau	F10 MV	Nov. 1928	115	175
Masson	H4AK	July 1933	115	140
Masson	H9A	Aug. 1940	115	160
Paugan	P33C	Oct. 1928	230	315
Paugan	P4C	July 1930	230	315
Rouyn	K2R	Dec. 1949	115	85
Rapide des Iles	D3KZ	Oct. 1966	115	100
Holden	1331	Oct. 1966	115	145
MANITOBA				
Kenora	SK1	Oct. 1956	115	75
	K21W	Oct. 1972	230	200
	K22W	Apr. 1973	230	200
NEW YORK				
Niagara	PA27	Dec. 1961	230	480
	BP76	May 1955	230	550
Cornwall	L33P	Dec. 1958	230	360
	L34P	Future(4)	230	360
MICHIGAN				
Sarnia	B3N	Sep. 1953	230	590
Windsor	J5D	Sep. 1953	230	570
Lambton	L4D	Dec. 1966	345	800
	L51D	1976	345	895

NOTES:

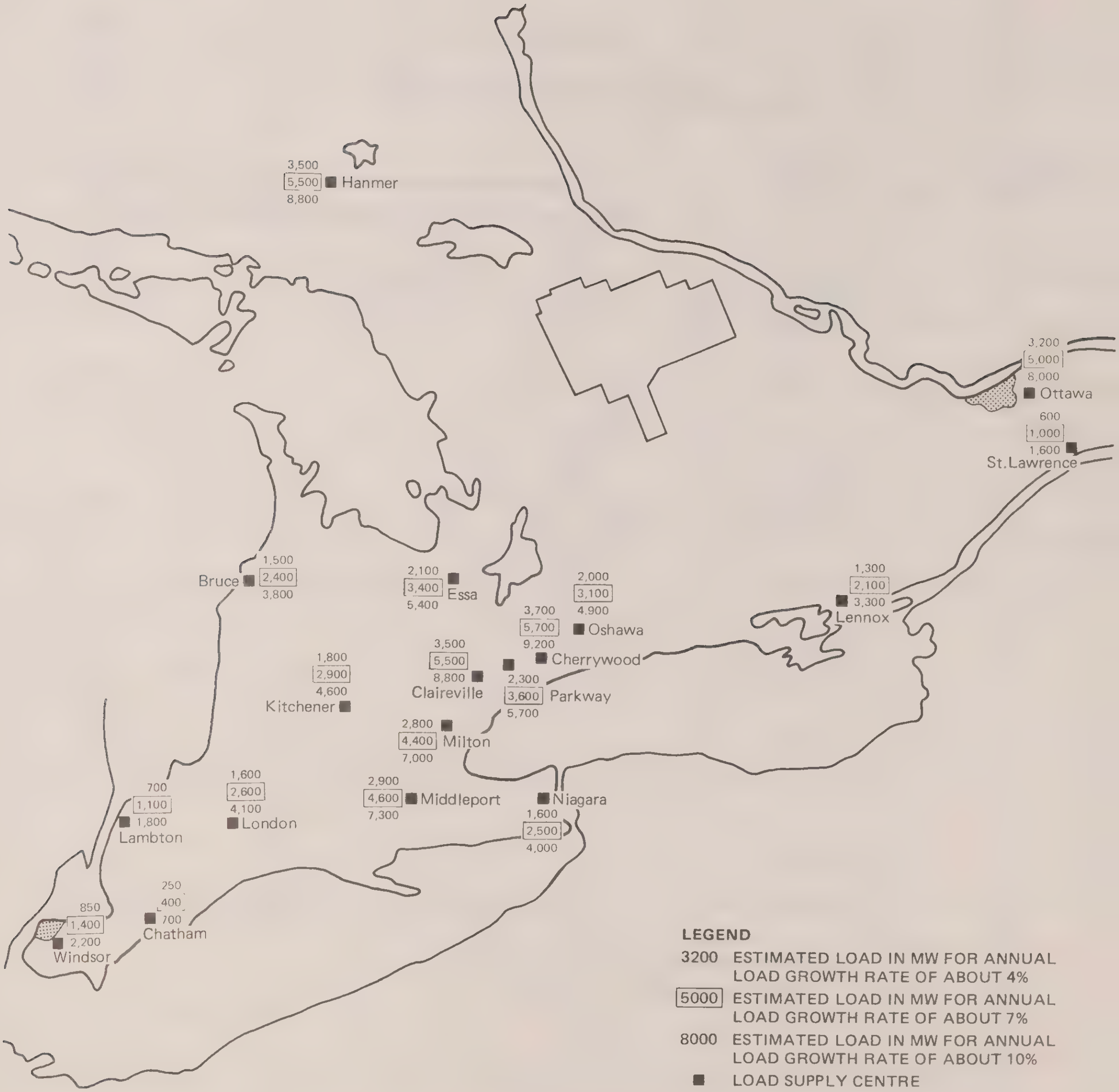
(1) The "date established" is the in-service date of the original interconnection. Changes to some of the interconnections have been made since to increase the voltage and/or the capacity.

(2) The Nominal Winter Capacities are based on the more limiting of the line or transformer capacity included in the interconnection.

(3) The total permissible interchange with the various utilities is not the arithmetic sum of the nominal capacities of the interconnections with that utility because power flows may not be shared by the interconnections in proportion to their capacities.

(4) L34P was originally placed in-service as HM3 in 1947 at 115 kV. It has not been used in recent years. Present plans are to re-establish this tie, with a phase shifter, for 230 kV operation.

FIGURE 9-4



ESTIMATED LOAD IN EAST SYSTEM IN 1995

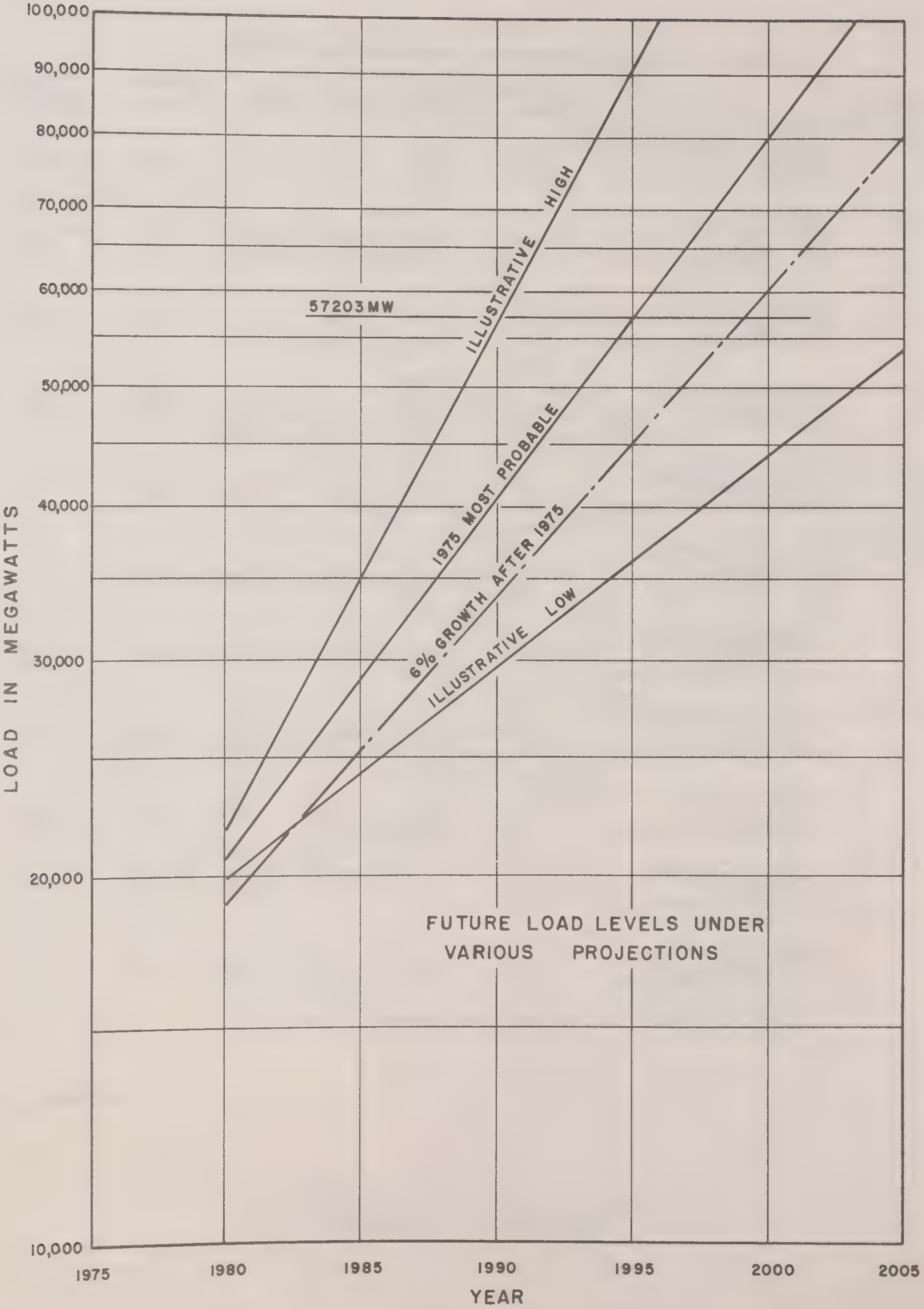
FIGURE 12–1

FIGURE 12-2

The Generation Proposed in Program LRF43P

Generating Station	Type	No. x Size of Units in MW	Units In-Service in Year Shown																				
			75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95
Nanticoke 5-8	F	4 x 531	1	1	2	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
Lennox	F	4 x 547	1	2	1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
Bruce A	N	4 x 750	.	1	1	1	1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
Wesleyville	F	4 x 547	.	.	.	.	1	1	2	.	.	.	.	.	.	.	.	.	.	.	.	.	.
Pickering B	N	4 x 516	.	.	.	.	.	1	2	1	.	.	.	.	.	.	.	.	.	.	.	.	.
Bruce B	N	4 x 750	.	.	.	.	.	.	.	1	1	1	1	.	.	.	.	.	.	.	.	.	.
Darlington	N	4 x 850	.	.	.	.	.	.	.	.	.	2	1	1	.	.	.	.	.	.	.	.	.
E-15	F	4 x 750	.	.	.	.	.	.	.	.	.	.	1	1	2	.	.	.	.	.	.	.	.
E-16	N	4 x 850	.	.	.	.	.	.	.	.	.	.	.	1	1	2	.	.	.	.	.	.	.
E-17	N	4 x 850	.	.	.	.	.	.	.	.	.	.	.	.	1	1	1	1	.	.	.	.	.
E-18	F	4 x 750	.	.	.	.	.	.	.	.	.	.	.	.	.	1	1	1	1	.	.	.	.
E-19	N	4 x 850	.	.	.	.	.	.	.	.	.	.	.	.	.	.	1	1	1	1	.	.	.
E-20	N	4 x 850	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	2	1	1	.	.
E-21	F	4 x 750	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	1	1	2	.	.
E-22	N	4 x 1200	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	1	1	1	1
E-23	F	4 x 750	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	2	1	1
E-24	N	3 x 1200	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	1	1	1
E-25	F	2 x 750	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	2
E-26	N	1 x 2000	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	1

FIGURE 12–2



100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
LOAD IN MEGAWATTS
1975
1980
1985
1990
1995
2000
2005
YEAR
57203 MW
ILLUSTRATIVE HIGH
1975 MOST PROBABLE
6% GROWTH AFTER 1975
ILLUSTRATIVE LOW
FUTURE LOAD LEVELS UNDER VARIOUS PROJECTIONS

FIGURE 12—3

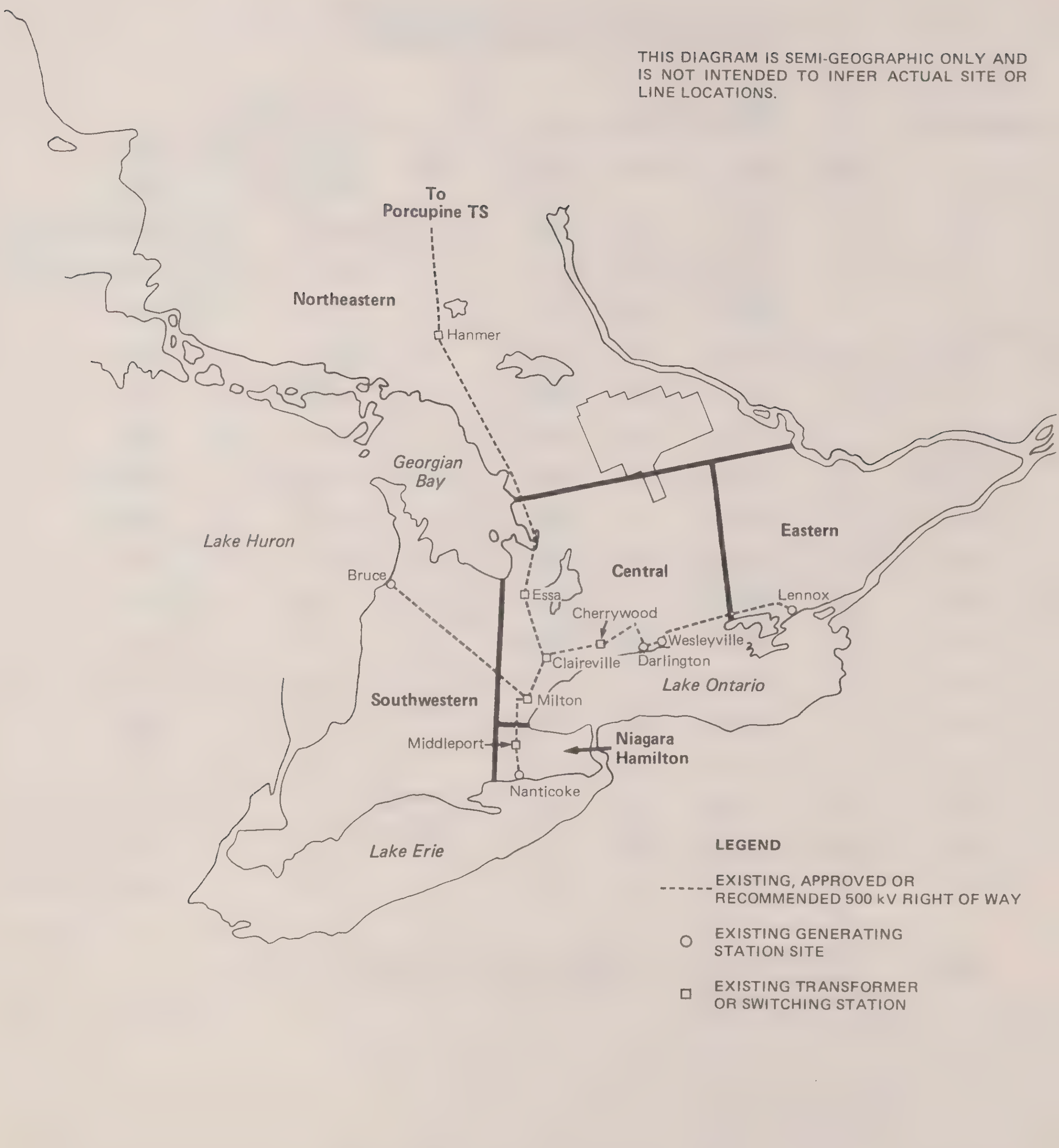
FIGURE 12-4

Distribution of Load and Generation in Conceptual Alternative Systems

Alternative		Southwestern Ontario	Niagara-Hamilton	Central Ontario	Eastern Ontario	Northeastern Ontario	Total East System
	Existing and Planned Generation - MW	8,911	6,170	14,163	3,423	1,809	34,476
	Forecast Load - MW	10,800	11,500	21,300	8,100	5,500	57,200
1 A,B,C	Number of New Sites	1	1	1	1	1	5
	Number of New Stations	1	2	4	2	2	11
	Total Generation	13,411	14,428	26,221	9,881	8,267	72,208
	Ratio of Generation to Load	1.24	1.25	1.23	1.22	1.50	1.26
2	Number of New Sites	-	-	1	2	1	4
	Number of New Stations	-	-	6	3	2	11
	Total Generation	8,911	6,170	35,837	13,023	8,267	72,208
	Ratio of Generation to Load	0.83	0.54	1.68	1.61	1.50	1.26
3 A,B,C	Number of New Sites	1	1	1	-	1	4
	Number of New Stations	2	3	4	-	2	11
	Total Generation	14,911	17,886	27,721	3,423	8,267	72,208
	Ratio of Generation to Load	1.38	1.56	1.30	0.42	1.50	1.26
4	Number of New Sites	1	1	1	1	-	4
	Number of New Stations	2	3	4	2	-	11
	Total Generation	14,911	17,886	27,721	9,881	1,809	72,208
	Ratio of Generation to Load	1.38	1.56	1.30	1.22	0.33	1.26
5 A,B,C	Number of New Sites	2	-	-	1	1	4
	Number of New Stations	6	-	2	2	1	11
	Total Generation	28,627	6,170	21,221	11,381	4,809	72,208
	Ratio of Generation to Load	2.65	0.54	1.00	1.41	0.87	1.26
6	Number of New Sites	-	1	1	2	1	5
	Number of New Stations	-	5	2	3	1	11
	Total Generation	8,911	24,802	19,163	13,023	6,309	72,208
	Ratio of Generation to Load	0.83	2.16	0.90	1.61	1.15	1.26
7 A,B,C	Number of New Sites	1	-	-	3	1	5
	Number of New Stations	2	-	1	7	1	11
	Total Generation	16,711	6,170	16,163	26,655	6,309	72,008
	Ratio of Generation to Load	1.55	0.54	0.76	3.29	1.15	1.26
8 A	Number of New Sites	-	-	-	1	3	4
	Number of New Stations	-	-	2	1	8	11
	Total Generation	8,911	6,170	19,763	6,423	30,941	72,208
	Ratio of Generation to Load	0.83	0.54	0.93	0.79	5.63	1.26
8 B	Number of New Sites	-	-	-	1	9	10
	Number of New Stations	-	-	2	1	9	12
	Total Generation	8,911	6,170	20,963	6,423	30,199	72,666
	Ratio of Generation to Load	0.83	0.54	0.98	0.79	5.49	1.27
9	Number of New Sites	1	1	1	2	2	7
	Number of New Stations	1	3	2	3	2	11
	Total Generation	11,911	17,886	22,663	13,281	6,867	72,608
	Ratio of Generation to Load	1.10	1.56	1.06	1.64	1.25	1.27

Note: For approximate load areas used in the summary, see Figure 12-5

FIGURE 12-4



APPROXIMATE LOAD AREAS USED FOR SUMMARY IN FIGURE 12–4

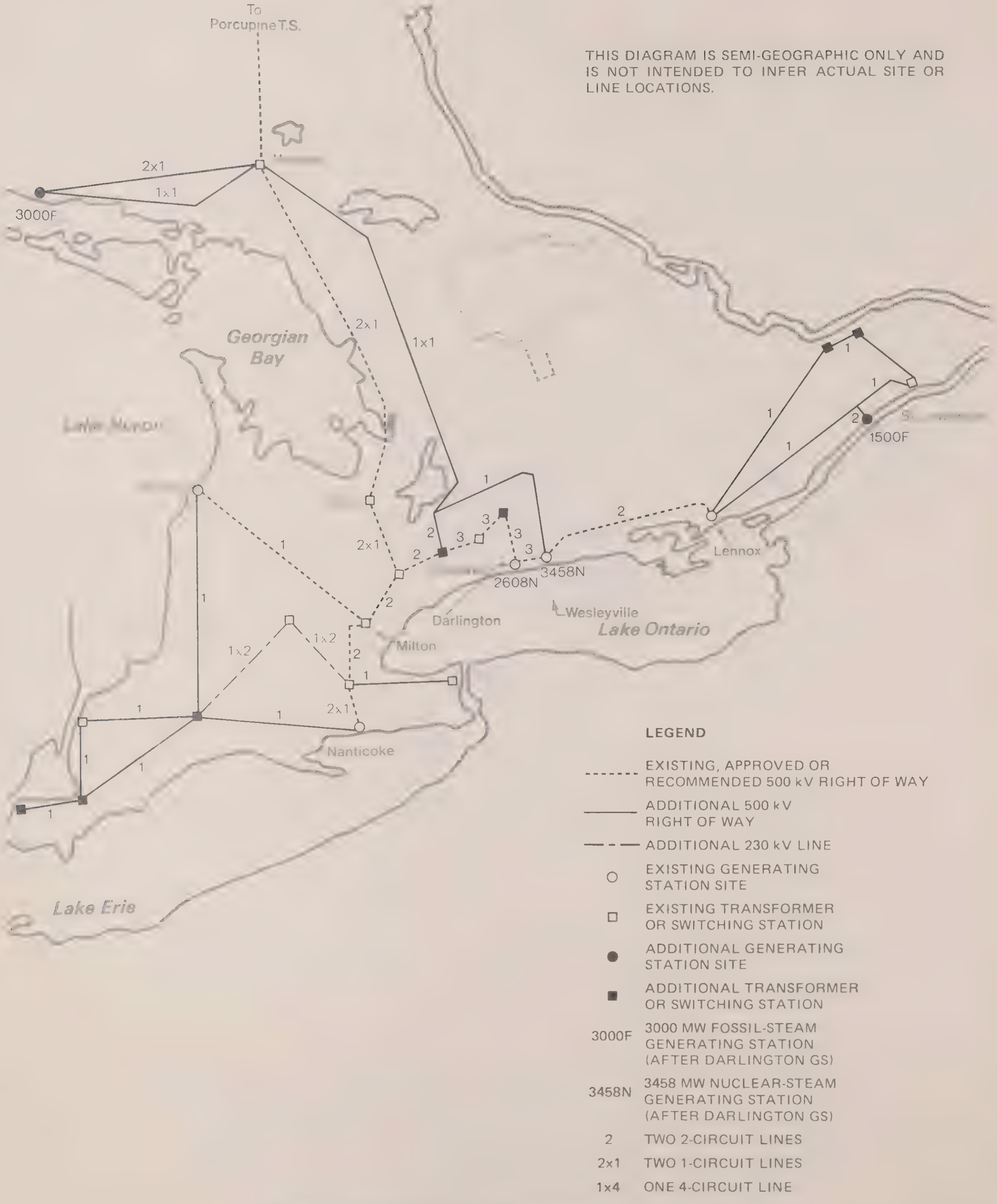
FIGURE 12–5

COMPARISON OF MILES OF NEW TRANSMISSION
AND ROUTES FOR CONCEPTUAL SYSTEMS

ALTERNATIVE	CIRCUIT MILES				ROUTE MILES			
	765kV	500kV	230kV	Total	765kV	500kV	230kV	Total
1A	-	3050	-	3050	-	1200	-	1200
1B	-	3100	400	3500	-	1250	-	1250
1C	-	2850	400	3250	-	1150	-	1150
2	-	3150	400	3550	-	1200	-	1200
3A	-	3550	-	3550	-	1350	-	1350
3B	-	3800	400	4200	-	1400	-	1400
3C	-	3300	400	3700	-	1300	-	1300
4	-	3150	-	3150	-	1050	-	1050
5A	-	3200	-	3200	-	1250	-	1250
5B	-	3100	400	3500	-	1200	-	1200
5C	-	3150	-	3150	-	1150	-	1150
6	-	3050	400	3450	-	1150	-	1150
7A	-	3850	-	3850	-	1400	-	1400
7B	-	3950	400	4350	-	1400	-	1400
7C	-	3750	400	4150	-	1300	-	1300
8A	3800	1700	400	5900	1450	750	-	2200
8B	3550	1700	400	5650	1600	750	-	2350
9	-	3100	-	3100	-	1200	-	1200

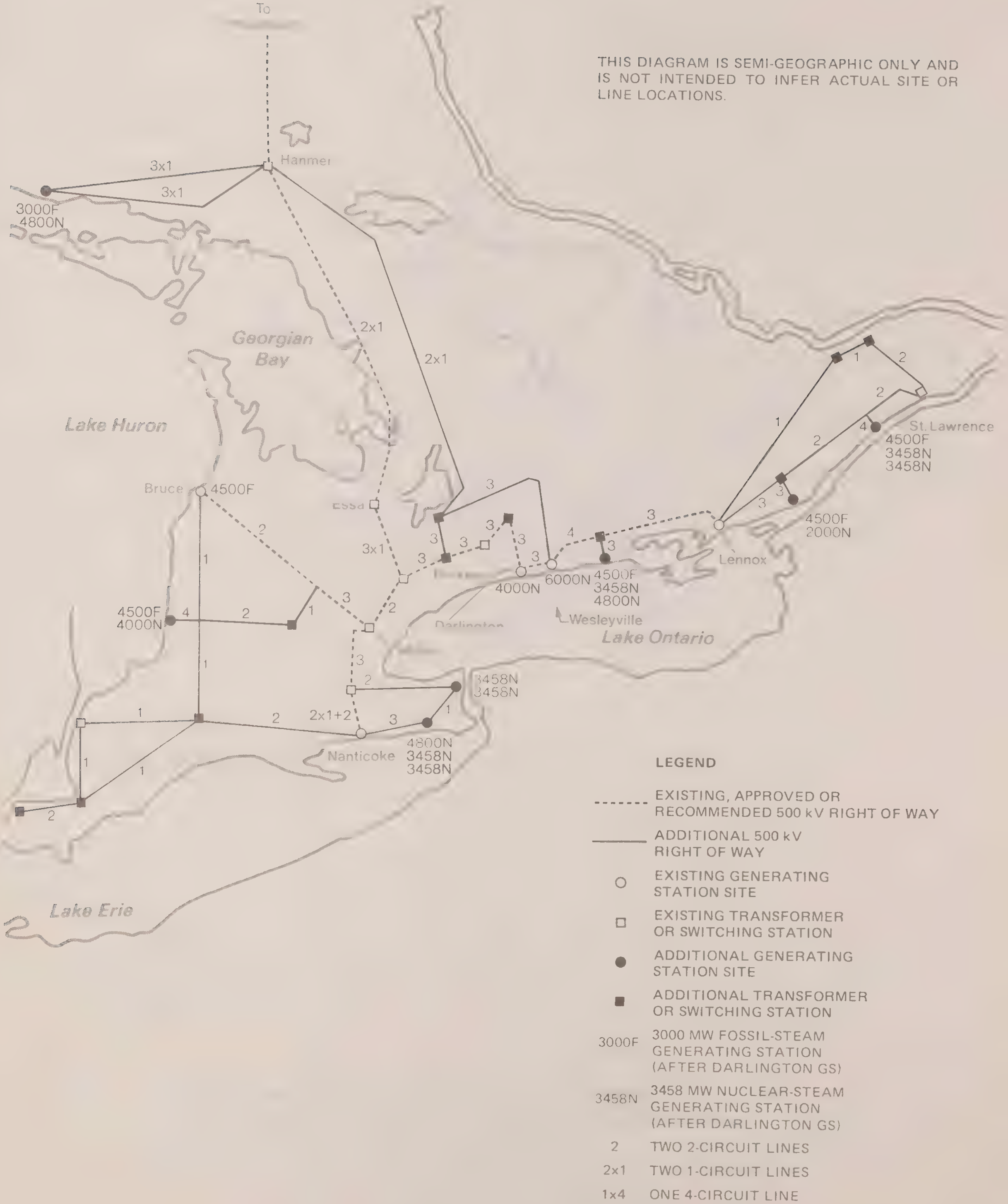
NOTE: - Transmission west of London and from Middleport to Niagara, which is common to all alternatives, is not included.

FIGURE 12–6



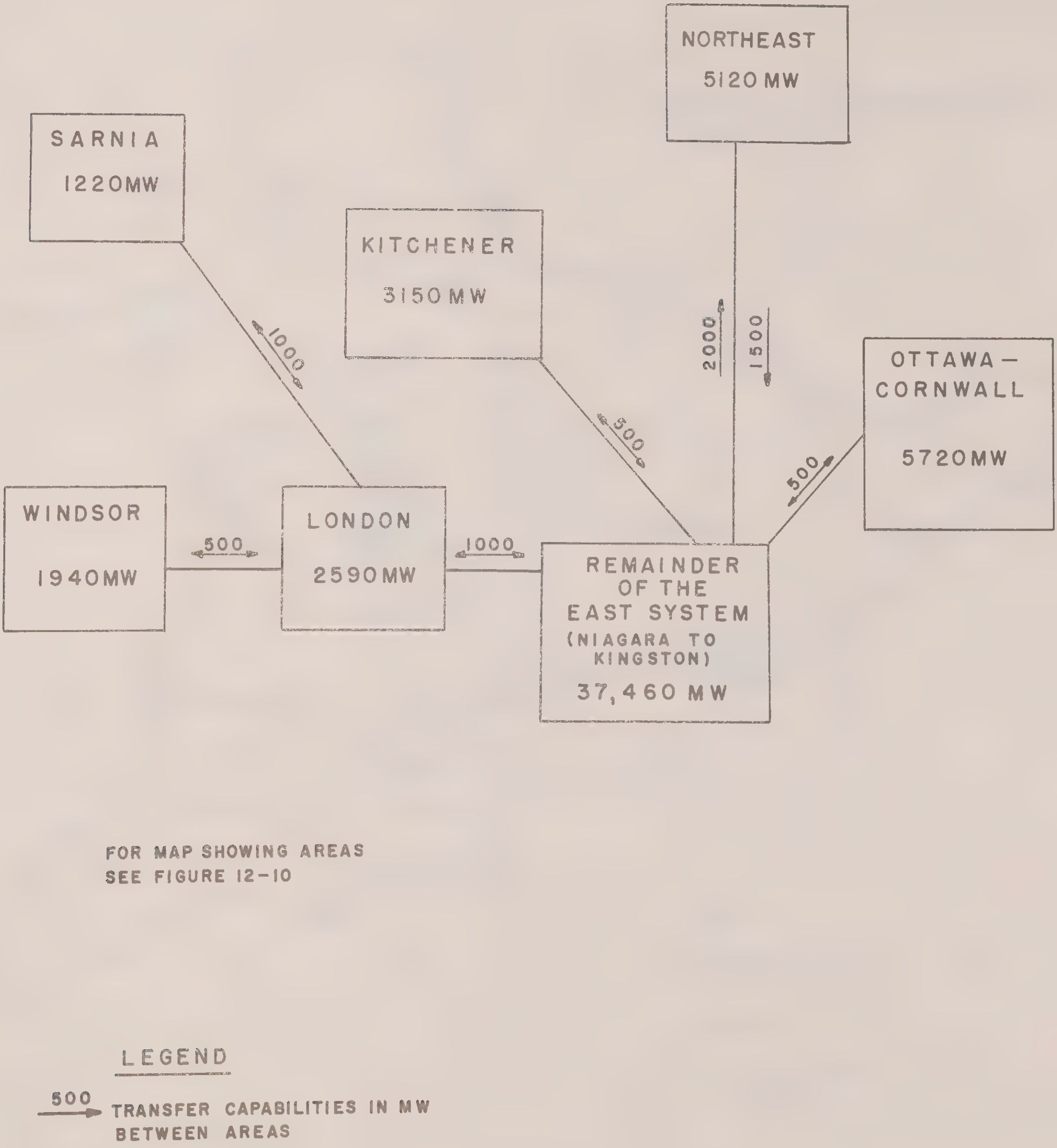
CONCEPTUAL EAST SYSTEM ARRANGEMENT
FOR MID–1990'S
Annual Load Growth – About 4%

FIGURE 12–7



CONCEPTUAL EAST SYSTEM ARRANGEMENT
FOR MID–1990'S
Annual Load Growth – About 10%

FIGURE 12–8



AREAS AND LOADS USED FOR STUDY OF ALTERNATIVE
SYSTEMS AIMED AT REDUCING NEW TRANSMISSION

FIGURE 12-9

ALTERNATIVE SYSTEMS TO REDUCE THE FUTURE REQUIREMENTS FOR NEW TRANSMISSION

LOCATION OF LOAD AREAS

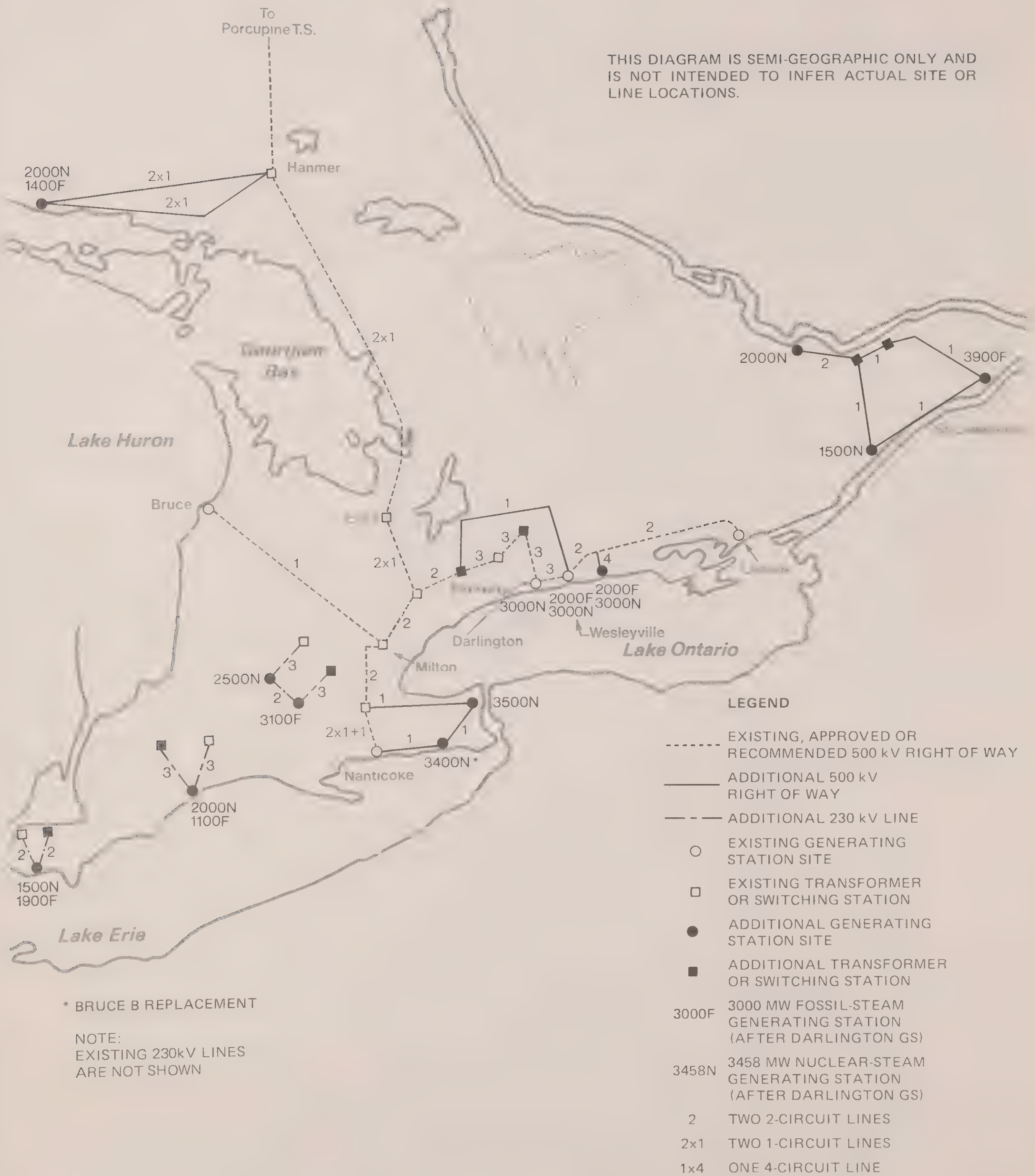
FIGURE 12—10

FIGURE 12-11

CAPACITY ADDITIONS
BEYOND THE FIRST FOUR 850 MW UNITS AT DARLINGTON GS

Area	Case 1 (Small Units)	Case 2 (Larger Units)	Case 3 (Larger Units and More Transmission)	Case 4 (Similar to Case 3 But Kitchener Included in "Remainder")	LRF43P
Remainder	25x500 N 8x500 F	1x2000 N 7x1200 N 2x850 N 10x750 F	1x2000 N 7x1200 N 2x850 N 9x750 F	1x2000 N 7x1200 N 5x850 N 12x750 F	1x2000 N 7x1200 N 8x850 N 6x750 F
Ottawa	7x500 N 7x500 F 2x200 F	7x500 N 7x500 F 2x200 F	7x500 N 6x500 F 1x200 F	7x500 N 6x500 F 1x200 F	4x850 N 4x750 F
Northeast	4x500 N 2x500 F 2x200 F	3x850 N 3x500 F	3x850 N 3x500 F	3x850 N 3x500 F	4x850 N 4x750 F
Kitchener	5x500 N 5x500 F 3x200 F	5x500 N 6x500 F	5x500 N 4x500 F 1x200 F	0	
London	4x500 N 1x500 F 1x200 F	4x500 N 1x500 F 1x200 F	4x500 N 1x200 F	4x500 N 1x200 F	4x750 F
Windsor	3x500 N 3x500 F 2x200 F	3x500 N 3x500 F 2x200 F	3x500 N 3x500 F	3x500 N 3x500 F	
Sarnia	0	0	0	0	0
Total	48x500 N 26x500 F 10x200 F	1x2000 N 7x1200 N 5x850 N 19x500 N 10x750 F 20x500 F 5x200 F	1x2000 N 7x1200 N 5x850 N 19x500 N 9x750 F 16x500 F 3x200 F	1x2000 N 7x1200 N 8x850 N 14x500 N 12x750 F 12x500 F 2x200 F	1x2000 N 7x1200 N 16x850 N 18x750 F
Nuclear (MW)	24,000	24,150	24,150	24,200	24,000
Fossil (MW)	15,000	18,500	15,350	15,400	13,500
Total	39,000	42,650	39,500	39,600	37,500
Capital Cost, Millions of Dollars, 1985 Costs					
Nuclear	39,202	33,554	33,554	32,920	30,685
Fossil	10,836	12,129	9,932	9,680	7,821
Total	50,038	45,683	43,486	42,600	38,506
Capital Cost Adjustments					
Nuclear	0	- 144	- 144	- 191	0
Reliability	- 312	- 215	- 350	- 464	0
Adjusted Capital Cost, Millions of Dollars, 1985 Costs	49,726	45,324	42,992	41,945	38,506

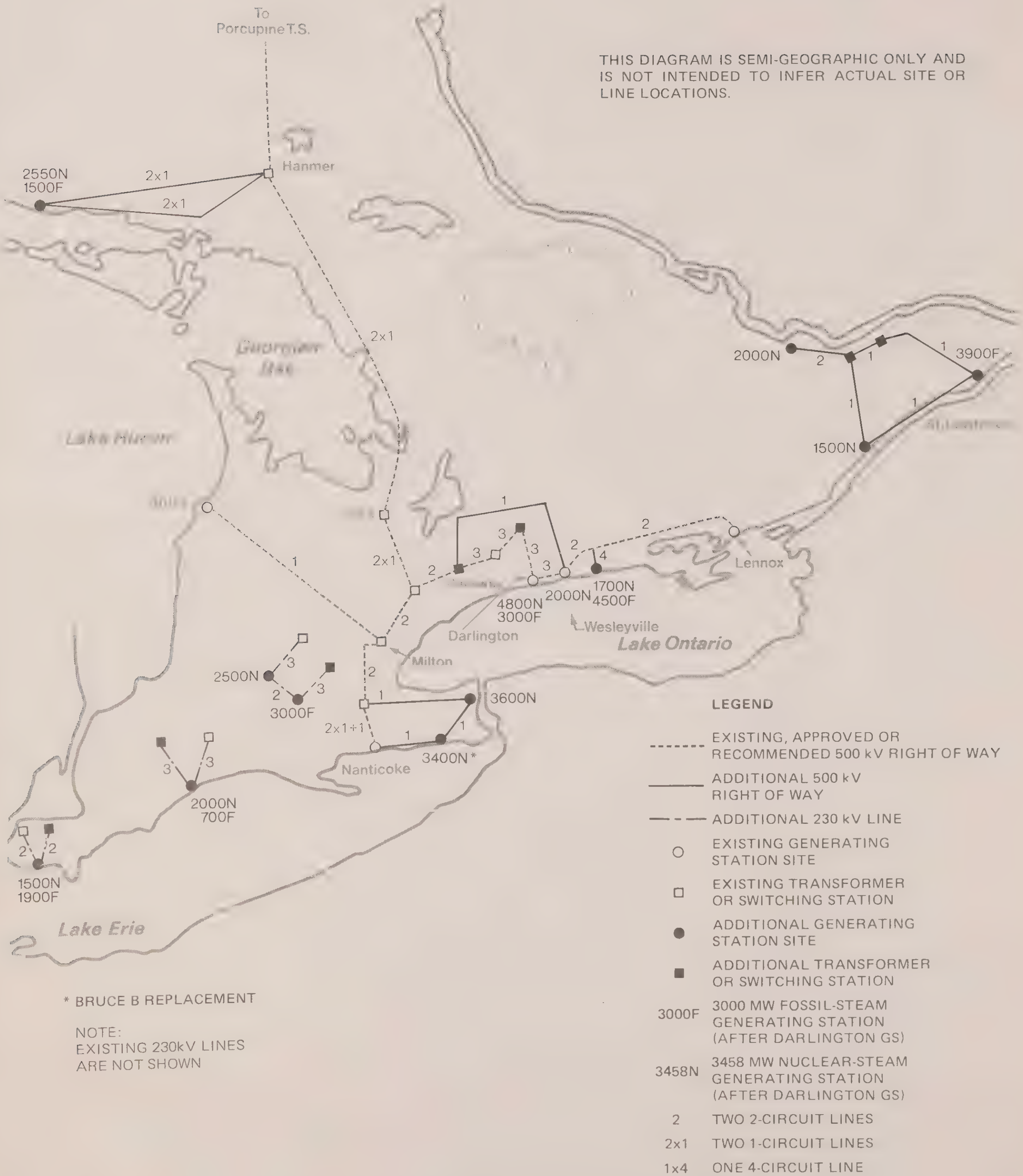
NOTE: 25x500 N represents 25 units of 500 MW size and nuclear type. F represents fossil-fuelled type.



ALTERNATIVE SYSTEMS TO REDUCE THE FUTURE REQUIREMENTS FOR NEW TRANSMISSION

CASE 1—SMALL GENERATING UNITS WITH MINIMUM INTERAREA TRANSMISSION

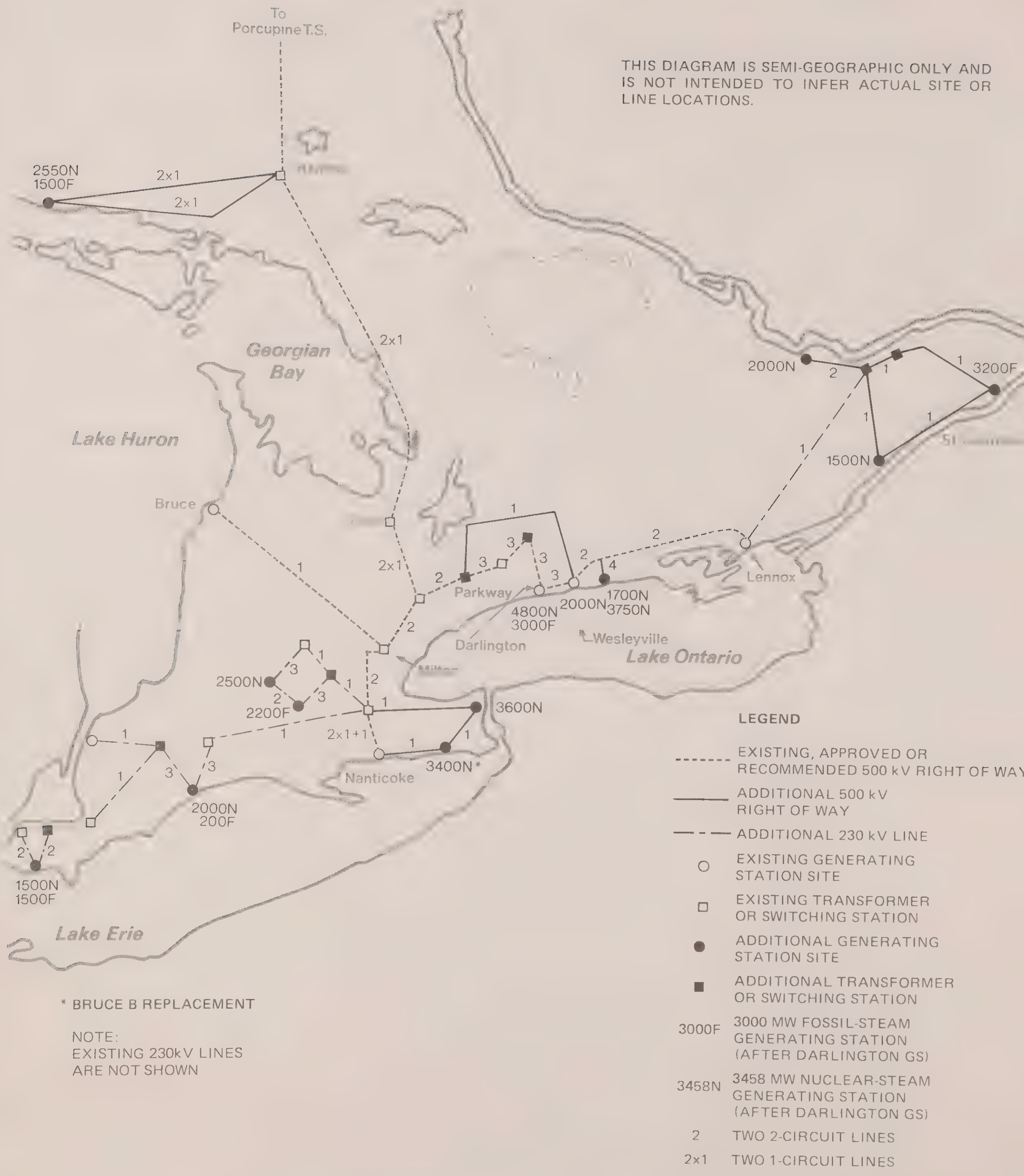
FIGURE 12—12



ALTERNATIVE SYSTEMS TO REDUCE THE FUTURE REQUIREMENTS FOR NEW TRANSMISSION

CASE 2—SAME AS CASE 1, EXCEPT FOR LARGER GENERATING UNITS IN SOME AREAS

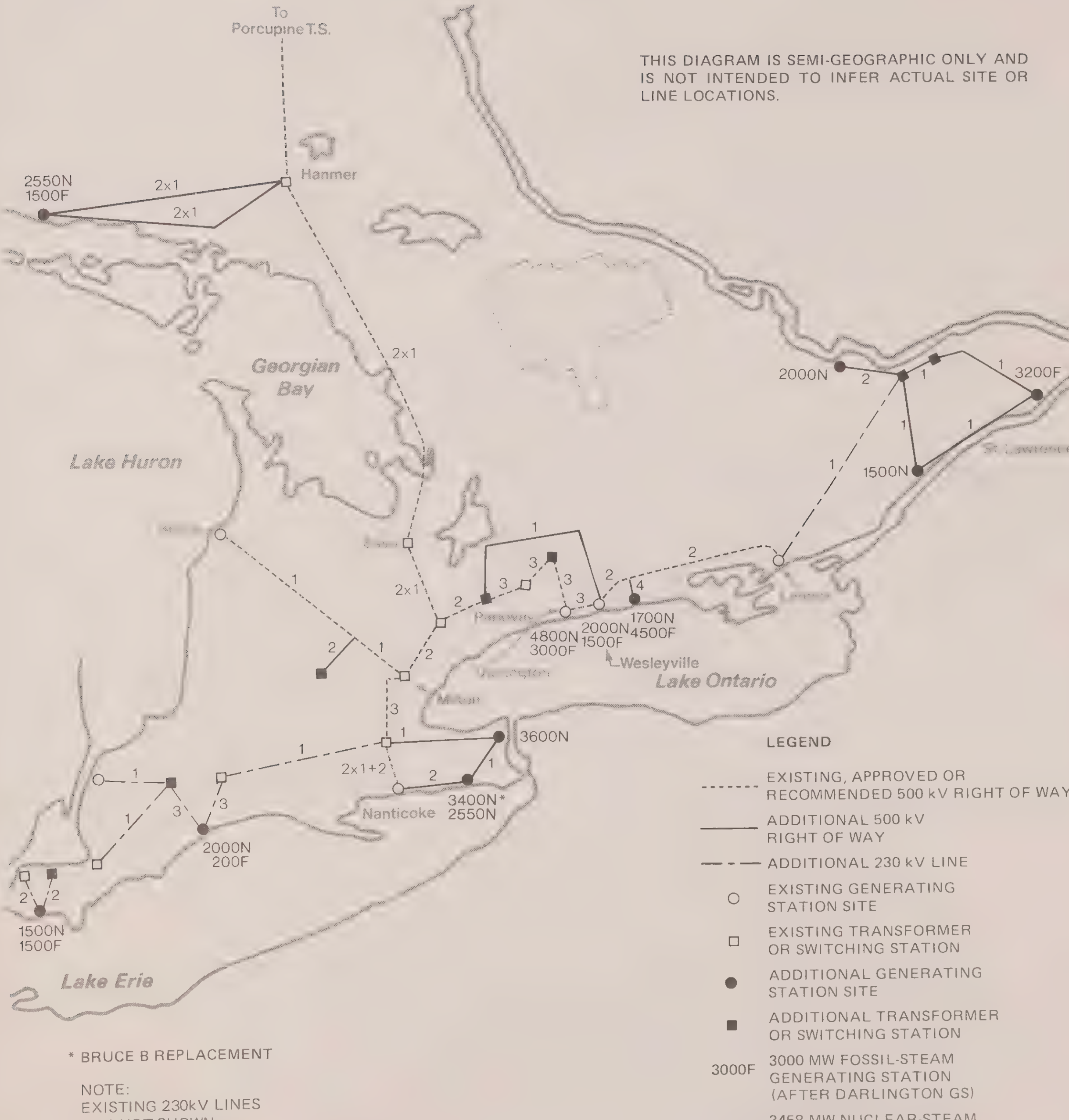
FIGURE 12–13



ALTERNATIVE SYSTEMS TO REDUCE THE FUTURE REQUIREMENTS FOR NEW TRANSMISSION

CASE 3—SAME AS CASE 2, EXCEPT FOR AN INCREASE IN INTER-AREA TRANSMISSION AND ADDITIONAL LARGER UNITS

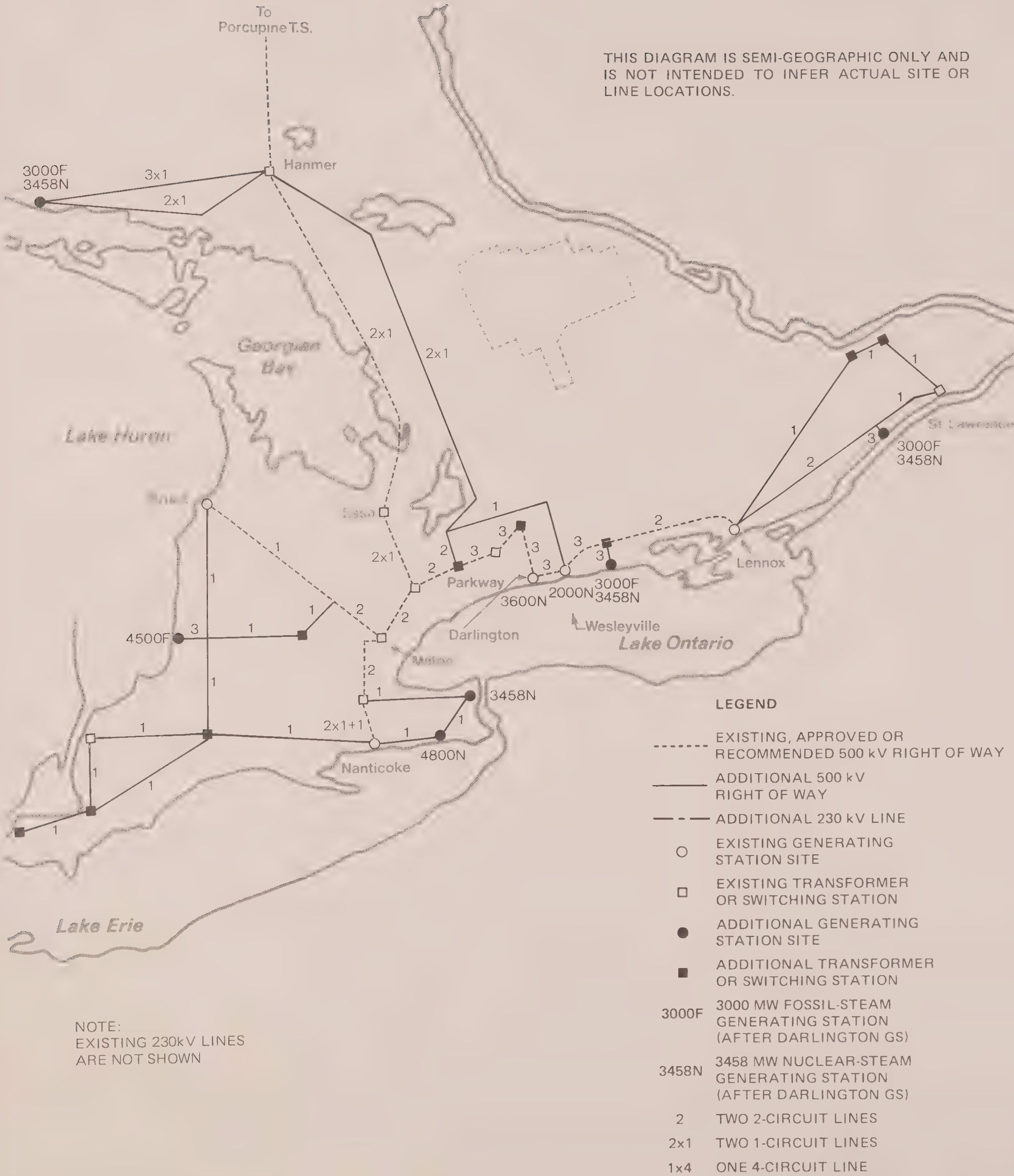
FIGURE 12–14



ALTERNATIVE SYSTEMS TO REDUCE THE FUTURE REQUIREMENTS FOR NEW TRANSMISSION

CASE 4—SAME AS CASE 3, EXCEPT WITH KITCHENER AREA SUPPLIED AT 500kV AND ADDITIONAL LARGER UNITS

FIGURE 12—15



BASE ALTERNATIVE USED FOR COMPARISON WITH CASES 1 TO 4
(GENERATION PROGRAM LRF43P—CONCEPTUAL SYSTEM 1A)

FIGURE 12—16

APPENDIX 2-A

Layman's Description of the
Electric Power Supply System in Ontario

A. Main System Components

The main system components are:

(a) Generators. These produce the electricity.

(b) Transformers. These change electric voltage upward or downward, as required.

(c) Transmission and Distribution Lines. These transport electricity from the point of generation to the point of use at customers' premises.

B. Generation

Electricity is produced in generators which are driven by turbines or engines. They include:

(a) Fossil-Fuelled (coal, lignite, gas, oil) Steam-Electric Stations

The turbines of these stations are driven by steam produced from heat, which is obtained by burning fossil fuels.

Lakeview
Generating
Station

(b) Nuclear-Fuelled Steam-Electric Stations

The turbines of these stations are driven by steam produced from heat which is obtained from nuclear fission.

Pickering Generating Station

(c) Hydraulic Stations

The turbines of these stations are driven by water falling through a vertical height.

Sir Adam Beck No. 1, Sir Adam Beck No. 2, and the Pumping Generating Station

(d) Hydraulic Pumped Storage Stations

The turbines of these stations are driven by water falling through a vertical height. However, in this case the water is pumped into an upper reservoir when the electric load is low and then allowed to fall through the turbines to generate electricity during hours when the electric load is high. The top right part of the above photograph shows the pumped storage reservoir at the Sir Adam Beck Station.

(e) Combustion Turbines and Diesels

These units are driven by hot gas produced by the combustion of fossil fuel.

Combustion Turbines at the Sarnia-Scott Transformer Station

C. Bulk Power Transmission

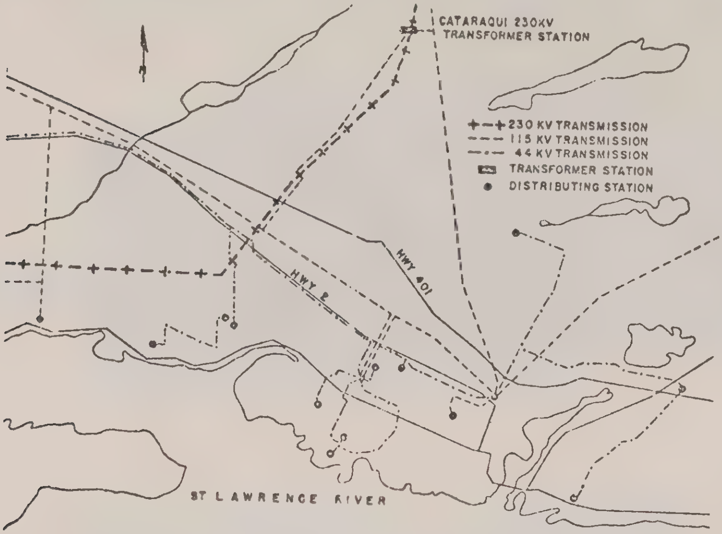
Electricity from generators is generally stepped up in transformers to a higher voltage for transport over a transmission system extending from the generating stations to centers of use or load centers. Ontario Hydro's bulk power transmission lines generally operate at voltages of 500 kV (500,000 volts), 230 kV, or 115 kV. The bulk power transmission network is designed so that the generation at a number of diverse locations can be used to supply the main load centers.

A 230 kV Double-Circuit Tower

D. Area and Regional Supply and Subtransmission

Near the load centers, electricity is taken from the bulk power transmission network and stepped down through transformers to lower voltages for transmission to locations closer to the loads. Voltages may range from 230 kV to

27.6 kV. This drawing shows the area supply and subtransmission in the vicinity of Kingston.



E. <u>Distribution</u>

At the load centers, electricity is stepped down through transformers to lower voltages, for distribution to locations adjacent to ultimate customers. At these locations the voltage is stepped down further to deliver electricity to customers at the voltages they use. Small customers take electricity at 115 volts or 230 volts, but large customers take electricity at higher voltages. This photograph shows a pole-top transformer which steps down voltage from 4 kV to the 115 or 230 volts used by customers in a residential subdivision.

A Pole-Top Distribution Transformer

F. Ownership of Facilities

In Ontario most of the distribution outside the areas served by municipal utilities, and most of the generation, bulk power transmission, area supply and subtransmission are owned by Ontario Hydro. However, some are owned by private companies (Great Lakes Paper Corporation, Abitibi Pulp and Paper Company, etc), and some are owned by municipalities (Orillia, Ottawa, etc).

Distribution within the municipalities is generally owned by the municipalities. They buy bulk power from Ontario Hydro and retail it to their customers.

G. Loads

In 1973, primary energy sales to Ontario customers by Ontario Hydro and the municipal electric utilities were as follows:

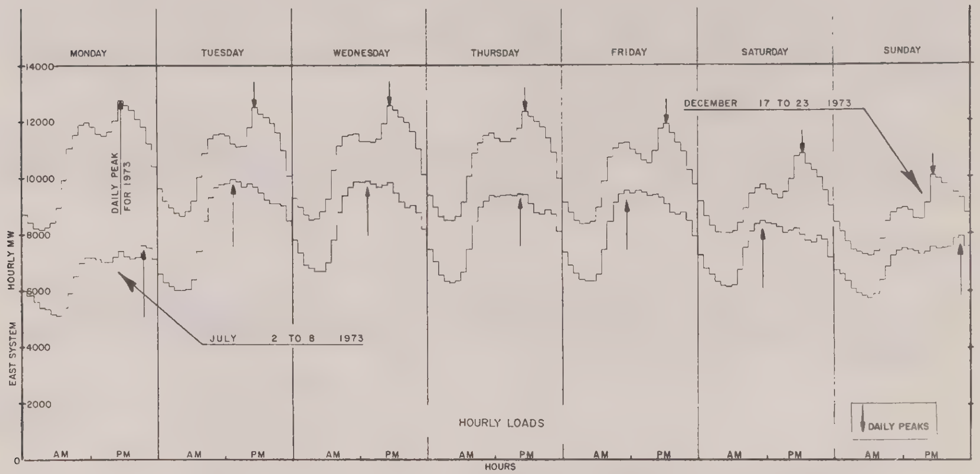
	Millions of kWh	Percent
Industrial, Commercial and Other Utilities	51,210	71.3%
Residential and Street Lighting	18,785	26.2%
Farm	1,789	2.5%
TOTAL	71,784	100.0%

The ultimate components of Ontario Hydro's load arise from hundreds of diverse uses:

> Water heaters, milking machines, household lights, blenders, chick brooders, mixers, saws, radios, tvs, furnaces, washers, dryers, refrigerators, stoves, floodlights, streetcars, boring mills, grinders, rolling mills, electrochemical equipment, etc.

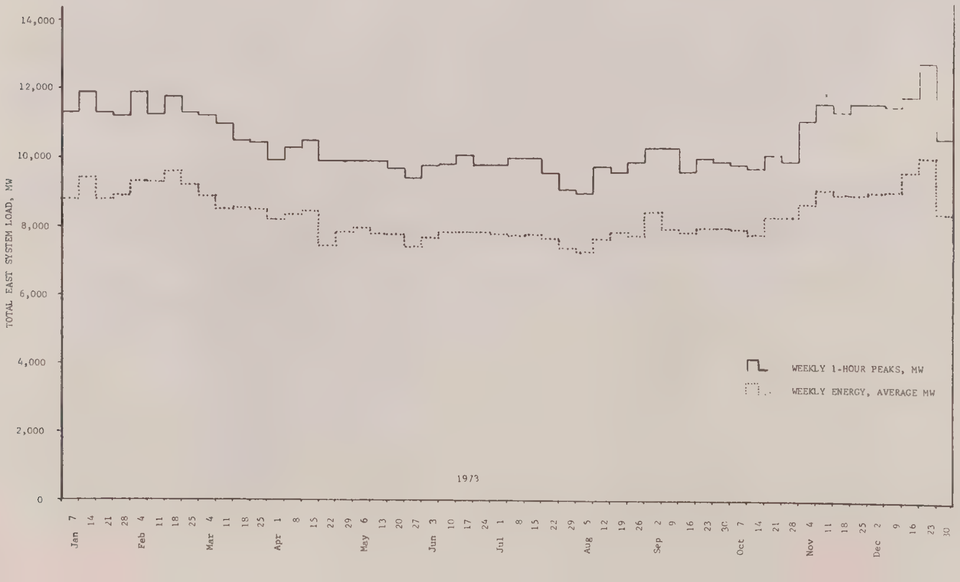
The patterns of use of each individual component are very diverse. However, their combined use results in total loads on the system which have relatively orderly patterns.

This figure shows the clock-hour load over a December week and over a July week for Ontario Hydro's East System.



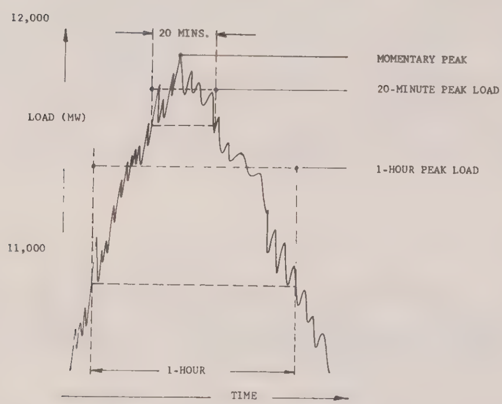
In both seasons the load is highest in daytime and lowest in nighttime and on weekends. The summer load is lower and has a flatter shape during the daytime. Winter daily peaks tend to occur in the hour from 5 to 6 pm, whereas those in the summer tend to occur at almost any hour in the day from 8 am to 6 pm.

The load patterns change in other months of the year and also may change from year to year. This figure shows the peak loads for each week and the energy, or average load, for each week throughout a year.



Summer loads are substantially lower than winter loads. The reduced loads in the non-winter period shown in the above figure enable Ontario Hydro to carry out the planned maintenance of its generating units in this period.

Within any hour the load is not constant as shown in the preceding figures, but varies from instant to instant as shown below:



The planning of the system must provide for meeting the momentary peak load. However, for statistical purposes, peak loads may be reported on a variety of bases, namely, in terms of momentary peak, 20-minute peak (which is the average load over a 20-minute period), one-hour peak, or clock-hour peak.

The ratio of the average load to the peak load in any period is termed the "load factor." Typical values are, for Ontario Hydro's East System:

85.9% for a winter working day
87.3% for a summer working day
64.9% for a calendar year

Load factors for Ontario Hydro's West System are greater than for its East System.

Under system emergencies, Ontario Hydro can reduce the electric load by:

(a) Instructing customers who purchase interruptible load to stop using, i.e. cut, this load. Ontario Hydro is permitted to do this under the contracts that it has with these customers.

(b) Reducing the supply voltage.

(c) Appealing to users through the public media to reduce their usage of power and energy.

(d) Deliberately discontinuing power supplies to users.

However, under any other conditions except emergencies, Ontario Hydro can deliberately discontinue or ration power supplies or restrict load growth only if it is authorized to do so by specific government regulations.

The load characteristics affect the operating conditions which must be met by the various power resources on the system. Ontario Hydro must have the ability to regulate the generator outputs to meet quickly changing demands. Ontario Hydro must be capable of reducing the energy production during the nighttime hours, of increasing it rapidly in the morning as load builds up, and of reducing it rapidly as the load falls off.

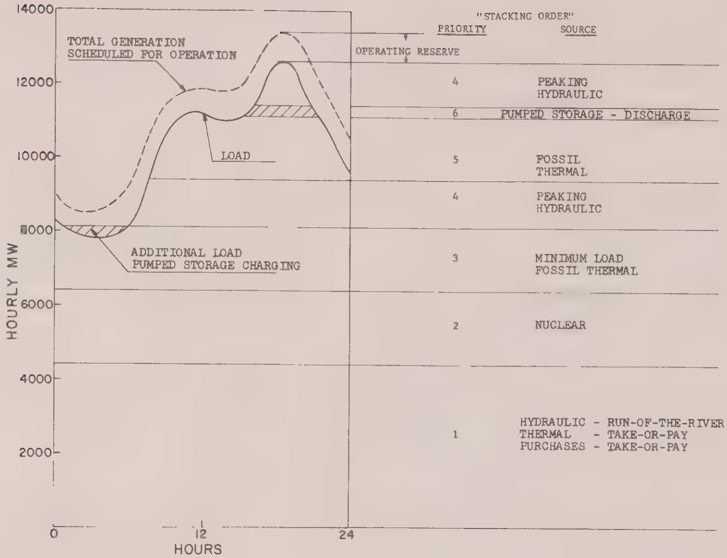
H. Operation of Generation

On an hour-by-hour basis, available generation must be operated to supply the load fully. Ontario Hydro's first consideration is to operate the system reliably, and its second consideration is to do this at lowest cost.

With the existing system, reliability requirements of the various areas in the Province necessitate the operation of generation located in diverse geographic locations, and the scheduling of generation operating reserves which must be held in readiness to replace unforeseeable failure of generating units.

Minimum cost considerations lead to specific "stacking" or "merit" order loadings of generation. At present these are generally aimed at achieving least possible use of coal and oil.

For a generating unit, the term "capacity factor" is used. It is the ratio of the actual average output of the unit in any period to the peak output that the unit is capable of generating.



I. Power Flows in Transmission Lines

As a result of the above factors, and others (e.g.: seasonal changes in output from hydraulic generation, purchases from and sales to systems outside Ontario, restrictions in fossil-fuelled generation due to air quality considerations, failures of units, failures of transmission and transformation, etc), patterns of power flows in the bulk power transmission system change from hour to hour and month to month. They also change from year to year as new generating stations and transmission are added to the system.

APPENDIX 5-A

Estimation of the Reliability of the Generating System and Ontario Hydro's Practices Respecting Generating Reserves

A. Unreliability of Generating Units

A generating station may contain several individual generating units. Each unit is not fully reliable, i.e., it is not available for operation at full load for 100% of the time. For part of the time it is derated (i.e., only a portion of its full output can be generated) or in an outage state (i.e., not available for operation at all).

In addition to causes associated with mechanical, electrical, and structural problems, generating units may suffer outages and deratings for many other reasons such as:

i) Normal weather variations

ii) Extremely adverse natural phenomena (tornado, severe temperature, flood, drought, earthquake, etc.)

iii) Strikes

iv) Shortages of materials

v) Government regulations, including those related to the environment

vi) Malicious damage or sabotage

vii) Personnel errors

viii) Etc.

B. Classification of Generating Unit Outages and Deratings

Among major North American electric utilities it is customary to consider all outages and deratings as falling into one of the following three conditions:

(a) Forced

A forced condition is a random one which requires a unit to be derated or taken out of service as soon as possible. (An analogy is a blowout in an automobile tire.)

(b) Maintenance

A maintenance condition is a random one, similar to a forced condition, but which does not require a unit to be

derated or taken out of service as soon as possible. Maintenance outages or deratings are generally scheduled for "safe" periods when they will not interfere with the utility's ability to supply load fully. (An analogy is a slow leak in an automobile tire.)

(c) Planned

A planned derating or outage is not random. It is scheduled in order to complete periodic overhauls; and it is generally scheduled several months in advance. (An analogy is replacement of an old tire by a new one.)

C. The Need for Generation Reserves

Because the reliability of the generating units is not as high as the reliability of electrical supply required by its users, Ontario Hydro must install a total generating capacity which exceeds the size of the total load. The amount of the excess is called the installed reserve.

The installed reserve is not unused capacity. It becomes used whenever generating units suffer outages or deratings.

In day-to-day operation, all units available for operation may not be operated. At times of lower loads, or when there are few deratings or outages of units, some of the units are shut down, i.e., taken out of operation even though they are capable of operation. This is done to reduce operating costs. It can be done without jeopardizing the reliability of electric supply, provided some generating capacity in excess of the load is operating or is capable of being started up quickly, in the event that any operating generation suddenly suffers forced outages or deratings.

System reliability is effected by two aspects of generating unit reliability: availability and security. Ontario Hydro judges its need for installed reserve generating capacity on the basis of the availability of its generating units using the method described in Section E. Security of the generating units is provided by designing them so that they have few sudden outages, so that they react properly to sudden stresses imposed during transmission system disturbances, and so that they are not damaged by such stresses.

Ontario Hydro has an intensive program to design improved reliability and maintainability into its new generating stations. This program includes utilization of operating experience, reliability and maintainability analysis, and design reviews. Reliability and maintainability requirements are included in the purchasing specification for major critical equipment, and expected performance is considered in evaluation of tenders.

It is anticipated that the results of this program will result in lower forced outage rates (which will permit reduced installed reserve margins) and higher availability (which will reduce costs of thermal energy production).

The actual operation and maintenance practices can have a significant effect on the reliability of generating units. This matter is under continual review in order to achieve overall economy of system operation.

D. Means of Computing Generating System Reliability

Ontario Hydro has computer programs which can be used to estimate the effects of generation being unavailable, due to forced, maintenance and planned outages and deratings, upon:

i) The Loss of Load Probability (LOLP) - This is the probability of being unable to supply daily peak loads fully.

ii) The Loss of Energy Probability (LOEP) - This is the probability of being unable to supply hourly energy loads fully.

iii) The Frequency (i.e., the number of occasions per year) and the Duration (i.e., the length of time) of failures to supply the hourly loads fully.

All these progams are based on probability techniques, and they estimate the effects of unreliability on the average.

None of the methods gives an absolute measure of reliability. All provide relative measures and for this reason they are of most value in designing a system to maintain a constant measure of reliability.

There is no outstanding advantage arising from using any one of these methods. Consistent application of any of the methods will lead to comparable requirements for future generation reserve.

All detailed studies of reliability clearly show that the actual level of reliability and the required reserve margins depend primarily on the number, size and forced outage rates of the generating units, and on the load characteristics. Therefore, comparisons of % reserve margins among utilities are valid only if the utilities are similar with respect to the above factors.

E. Ontario Hydro's LOLP Computation

In practice, Ontario Hydro has used a LOLP computation in reaching decisions upon required reserve generating capacity.

Ontario Hydro's computation is similar in principle to, but different in details from, LOLP computations that are made by other large utilities in North America. It includes the following steps, for each month in the period under study:

(1) Estimate the peak loads on each of the normal working days in the month.

(2) Estimate the generating units that will be out of service for planned maintenance. Hence derive the generating units that are potentially capable of being operated.

(3) For the units that are potentially capable of being operated, estimate the total capacity that will be fully operable, after taking account of forced outages and deratings. This estimate is done on a probability basis, using a mathematical model. The input to the model is a listing for each generator of its peak output capacity and its estimated characteristics of forced outages and forced deratings. The output from the model is a listing for the total generation on the system showing the probability that various total amounts of generation will be in an operable condition.

Ontario Hydro's computation for its East System takes account of the variability in output of the Sir Adam Beck-Niagara hydraulic generating complex, and of forced outages and deratings of thermal units. Because these have only a minor affect, it takes no account of the variability in peak output of other hydraulic stations, of forced outages and deratings of any hydraulic units and gas turbines. Except in December and January in the case of the Quebec purchase, no account is taken of possible failures in firm power purchases from Quebec and Manitoba.

Ontario Hydro's computation for its West System does take account of the forced outages of hydraulic and gas turbine units.

(4) Combine the peak load estimates from (1) with the probability of having operable generation from (3), to compute the probability that insufficient operable generation will be available to supply the daily peak loads throughout the whole month. This is the Loss of Load Probability (LOLP).

The probability can be expressed as a per cent, decimal, or ratio. Typically it is expressed as a ratio using the number of normal working days in 5 or 10 years as the denominator. Ontario Hydro uses 10 years, for which it assumes that the number of normal working days is 2400. In the recent past, it has planned generation to meet a LOLP of about 1 in 2400 in December. This implies that, if all months are similar to December, on the average, for 1 day in 10 years generation will be inadequate to supply the total estimated firm load.

The LOLP computation as it is used at present has shortcomings, as can be seen from the fact that:

It accounts for:	It does not account for:
(a) Estimated forced outages and deratings of major generating units, assuming the operating state of each unit is independent of the states of all other units.	(a) Forced outages and forced deratings of major units which occur coincidentally or which overlap with one another because they are interrelated. The effects of these events can be substantial, but it is difficult to estimate their probability of occurrence.
(b) Estimated planned outages and deratings.	(b) Estimated maintenance outages and maintenance deratings. It is assumed that these can be completed on weekends, although this is sometimes impossible. It is also assumed that weekend generation reserves will be large because the load levels are substantially lower on weekends than other days. This situation may change in the future.
(c) Variations in hydraulic outputs at Sir Adam Beck-Niagara GS due to normal river flow variations.	(c) Variations in hydraulic outputs at other stations or at Sir Adam Beck-Niagara GS due to severe icing or wind conditions.
(d) Variations in the outputs of gas turbine and steam turbine units due to normal changes in temperature.	(d) Variations in these outputs due to extreme temperatures.
(e) Reductions in generating unit outputs due to known government regulations.	(e) Reductions in generating unit outputs due to unforeseen government regulations.
(f) Cutting of interruptible loads.	(f) Conversion of interruptible loads to firm loads.

(g) The possibility that new generation will come into service ahead of schedule or behind schedule.

(h) Strikes.

(i) Shortages of critical materials such as fossil fuels, nuclear fuels, heavy water, lubricating oils, etc.

(j) Transmission being inadequate to transmit power from the generators to the users.

(k) The energy production limitations at hydraulic stations.

(l) The possible failure of Quebec or Manitoba to deliver contracted firm power, except in the case of Quebec deliveries in December and January.

(m) Malicious damage.

(n) Actual firm peak loads being greater or less than forecast.

(o) The possible reduction in load by lowering supply voltages to users.

(p) The possible assistance available from other utilities by virtue of the interconnections.

(q) Actual forced, maintenance and planned outages and deratings being greater or less than forecast.

It is theoretically possible to include in the LOLP computation many of the factors not now accounted for. Some of the factors can be readily included in the computation. But for others, a major obstacle in including them arises from the difficulty, and in some cases the impossibility, of assigning appropriate

probability factors to the events and in assessing all the ramifications of the events. However, many of the events from time to time do occur and result in major reductions in the capability of Ontario Hydro's generation.

F. Selection of the Level of Generation Reserves

It is not yet possible to compute the appropriate balance between the cost and the reliability of the generating system, because:

(a) no means yet exist to compute within reasonable error the absolute level of reliability of the supply of primary energy and materials, the physical reliability of the generating units, the competence of personnel, etc., and,

(b) the monetary value of various alternative degrees of reliability of the supply of electric power and energy to the users is not yet known.

In practice, Ontario Hydro uses its LOLP computations as a starting point in assessing its reserve requirements. Ontario Hydro's criterion is that the LOLP should be no greater than 1 in 2400 in any month. This normally results in the requirements being set by December and January conditions, since the highest loads usually occur in these months.

The realism of setting reserves at this computed level is then reviewed in the light of the known shortcomings of the probability method as applied by Ontario Hydro, and the availability of resources, including capital funds and primary energy supplies.

With respect to primary energy supplies for its generating stations, it is Ontario Hydro's position that it will achieve a more reliable energy supply by developing CANDU nuclear reactors using Canadian uranium than by developing fossil-fuelled generation dependent on USA coal or Canadian coal, gas or oil, or foreign oil, or by developing other types of nuclear reactors.

APPENDIX 5-B

Seasonal Peak and Energy Characteristics of Ontario Hydro's Generating Resources

This attachment indicates the monthly and annual characteristics of Ontario Hydro's existing generating resources. To eliminate non-seasonal effects due to changes in the quantity of these resources throughout the year, the data are limited in two ways:

- For all resources except the 187 MW firm purchase from Hydro-Quebec, the resources shown are those in commercial service by January, 1976. Thus, the data exclude the capability of new resources forecast to come into commercial service after January, 1976.

- The resources shown exclude in all months the 187 MW firm purchase from Hydro-Quebec which expires on November 1, 1976.

As noted in Table 1, none of the data shown in this attachment takes account of the forced, planned, or maintenance outages or partial deratings of generating resources. In practice, these will occur and their effect is substantial.

The following material is provided:

	Table Number of Data for East System	Table Number of Data for West System
(a) Definitions of Generating Resources	1	1
(b) 1976 Peak Resources in MW, all months	2	5
(c) 1976 Energy Resources in Average MW, all months	3	6
(d) 1976, August, December and Annual Data, and Most Frequent Mode of Operation	4	7
(e) 1976 Monthly Peak and Energy Resources in Chart Form	8	8

TABLE 1

Definitions of Generating Resources

Data for generating units are based on the following definitions:

(a) Hydraulic Resources

Peak Resource (MW)

This is the peak rating of a hydraulic unit, which is the maximum net power available to supply system load for at least 5 days per week, for daily uninterrupted periods equal to:

i) Two hours for the East System, excluding the Sir Adam Beck plants.

ii) Twenty minutes for the Sir Adam Beck installations.

iii) Eight hours for all West System plants.

Energy Resource (Average MW)

This is the energy generating capability of a hydraulic unit, which is the maximum net energy available to supply system load within a month for the East System and a year for the West System.

Alternatives Shown

Hydraulic peak and energy resources are based on monthly mean river flows. They are shown for two alternative values:

i) Dependable values, attainable or exceeded 98% of the time.

ii) Median values, attainable or exceeded 50% of the time.

(b) Thermal Resources

Peak Resource (MW)

This is the peak rating of a thermal unit, which is the maximum net power available to supply system load for a minimum of two hours a day, without exceeding specified limits of equipment stress.

Energy Resource (Average MW)

This is the energy generation of a thermal unit, which is the maximum net energy available to supply system load within a month for the East System and a year for the West System.

The value shown is the Maximum Continuous Rating (MCR) of a unit, i.e., its design net electrical output when it is operating continuously. The rating may be adjusted after commissioning the unit.

The peak and energy capability for nuclear and fossil-steam thermal resources shown include no variation from month to month as a result of weather or environmental factors. Studies of the effects of possible regulations governing circulating water usage are under way. Their outcome may require downward revisions in the estimated capability of these resources.

The peak and energy capability of combustion turbine units reflect the effects of ambient temperature limitations.

Measurement of Resources

All peak and energy resources shown are the net outputs sent out to the system at the low voltage terminals of the step-up transformers.

No account is taken of forced, planned, or maintenance outages or partial deratings of generating units which occur from time to time.

TABLE 2 - SHEET 1

ONTARIO HYDRO - EAST SYSTEM

1976 PEAK RESOURCES IN MW, ALL MONTHS

Hydraulic - Dependable	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Abitibi Canyon	226.0	226.0	226.0	224.0	222.0	224.0	224.0	226.0	225.0	224.0	226.0	226.0
Barrett Chute	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Chats Falls	81.0	82.0	80.0	69.0	68.0	69.0	71.0	82.0	80.0	70.0	70.0	73.0
Chenaux	116.0	116.0	116.0	89.0	66.0	75.0	102.0	116.0	116.0	100.0	99.0	108.0
Des Joachims	372.0	372.0	359.0	336.0	314.0	330.0	364.0	372.0	370.0	362.0	363.0	367.0
Harmon	128.0	128.0	126.0	125.0	141.0	124.0	124.0	125.0	124.0	124.0	124.0	125.0
Holden	190.0	190.0	188.0	189.0	190.0	191.0	208.0	203.0	207.0	204.0	200.0	193.0
Kipling	142.0	142.0	142.0	139.0	133.0	138.0	141.0	142.0	141.0	140.0	142.0	142.0
Little Long Rapids	126.0	127.0	125.0	125.0	126.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Mountain Chute	165.0	165.0	154.0	154.0	163.0	164.0	165.0	166.0	167.0	165.0	164.0	164.0
Niagara, SAB + PGS - CNP	1645.0	1511.0	1755.0	1341.0	1383.0	1383.0	1353.0	1343.0	1315.0	1277.0	1790.0	1745.0
Ontario Power	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	7.0	.0
DeCew Falls	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
Otter Rapids	178,0	175.0	176.0	176.0	172.0	176.0	176.0	176.0	176.0	176.0	176.0	177.0
Aubrey Falls	158.0	158.0	153.0	153.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0
Rayner - Wells	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0
Red Rock Falls	40.0	40.0	39.0	36.0	35.0	37.0	40.0	40.0	40.0	38.0	38.0	40.0
Stewartville	168.0	168.0	168.0	167.0	167.0	168.0	168.0	169.0	169.0	168.0	168.0	168.0
Lower Notch	260.0	265.0	266.0	251.0	247.0	248.0	248.0	260.0	256.0	249.0	250.0	252.0
St. Lawrence - Saunders	790.0	784.0	790.0	660.0	662.0	687.0	710.0	716.0	710.0	694.0	693.0	696.0
Georgian Bay	29.0	29.0	29.0	29.0	29.0	29.0	29.0	30.0	29.0	29.0	29.0	29.0
Bal. In EO Div.	50.0	50.0	50.0	46.0	46.0	50.0	50.0	51.0	51.0	50.0	50.0	50.0
Bal. In NE Region	60.0	60.0	58.0	55.0	51.0	55.0	56.0	59.0	59.0	57.0	57.0	58.0
Total All Plants	5526.0	5390.0	5602.0	4966.0	4975.0	5033.0	5114.0	5161.0	5120.0	5012.0	5531.0	5498.0
Diversity	48.0	41.0	67.0	149.0	181.0	184.0	96.0	45.0	59.0	127.0	118.0	79.0
Total Hydraulic - Dependable	5574.0	5431.0	5669.0	5115.0	5156.0	5217.0	5210.0	5206.0	5179.0	5139.0	5649.0	5577.0

TABLE 2 - SHEET 2

ONTARIO HYDRO - EAST SYSTEM RESOURCES

1976 PEAK RESOURCES IN MW, ALL MONTHS

Hydraulic - Median	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Abitibi Canyon	226.0	226.0	226.0	226.0	225.0	226.0	226.0	226.0	226.0	226.0	226.0	226.0
Barrett Chute	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Chats Falls	84.0	84.0	84.0	77.0	74.0	81.0	84.0	84.0	84.0	84.0	84.0	84.0
Chenaux	116.0	116.0	116.0	116.0	114.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0
Des Joachims	372.0	372.0	360.0	348.0	358.0	372.0	372.0	372.0	372.0	372.0	372.0	372.0
Harmon	131.0	131.0	131.0	141.0	141.0	141.0	131.0	129.0	131.0	131.0	130.0	130.0
Holden	213.0	206.0	200.0	211.0	220.0	218.0	219.0	219.0	219.0	216.0	216.0	214.0
Kipling	142.0	142.0	142.0	142.0	139.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0
Little Long Rapids	129.0	130.0	129.0	126.0	126.0	126.0	125.0	127.0	127.0	126.0	126.0	128.0
Mountain Chute	167.0	167.0	154.0	154.0	166.0	166.0	167.0	167.0	167.0	167.0	167.0	167.0
Niagara SAB + PGS - CNP	1813.0	1813.0	1813.0	1635.0	1732.0	1748.0	1750.0	1704.0	1653.0	1627.0	1844.0	1844.0
Ontario Power	105.0	105.0	105.0	.0	.0	.0	.0	.0	.0	.0	105.0	105.0
DeCew Falls	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
Otter Rapids	179.0	179.0	178.0	178.0	179.0	178.0	178.0	179.0	178.0	179.0	178.0	179.0
Rayner - Wells	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0
Red Rock Falls	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Aubrey Falls	158.0	158.0	153.0	153.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0
Stewartville	169.0	169.0	168.0	168.0	168.0	168.0	169.0	169.0	169.0	169.0	169.0	169.0
Lower Notch	270.0	274.0	275.0	269.0	253.0	258.0	263.0	265.0	266.0	268.0	268.0	267.0
St. Lawrence - Saunders	818.0	818.0	820.0	820.0	835.0	839.0	846.0	852.0	832.0	814.0	782.0	764.0
Georgian Bay	30.0	30.0	29.0	29.0	29.0	30.0	30.0	30.0	30.0	30.0	30.0	29.0
Bal. In EO Div.	51.0	51.0	51.0	46.0	47.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
Bal. In NE Region	60.0	60.0	60.0	58.0	58.0	59.0	60.0	60.0	60.0	60.0	60.0	60.0
Total All Plants	5875.0	5873.0	5836.0	5539.0	5664.0	5719.0	5729.0	5692.0	5623.0	5578.0	5866.0	5847.0
Diversity	-6.0	-15.0	1.0	-18.0	-22.0	-23.0	26.0	15.0	24.0	14.0	.0	-10.0
Total Hydraulic - Median	5869.0	5858.0	5837.0	5521.0	5642.0	5696.0	5755.0	5707.0	5647.0	5592.0	5866.0	5837.0

TABLE 2 - SHEET 3

ONTARIO HYDRO - EAST SYSTEM

1976 PEAK RESOURCES IN MW, ALL MONTHS

Nuclear Thermal	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Douglas Point	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0
NPD	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Pickering 1-4	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0	2056.0
Total Nuclear Thermal	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0	2284.0
Fossil-Steam Thermal												
R.L. Hearn 1-4	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0
R.L. Hearn 5	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0
R.L. Hearn 6-8	600.0	600.0	600.0	600.0	591.0	591.0	591.0	591.0	591.0	591.0	600.0	600.0
J.C. Keith 1-4	256.0	256.0	256.0	256.0	256.0	256.0	256.0	256.0	256.0	256.0	256.0	256.0
Lakeview 1-2	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0
Lakeview 3-6	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0	1140.0
Lakeview 7-8	590.0	590.0	590.0	590.0	590.0	590.0	590.0	590.0	590.0	590.0	590.0	590.0
Lambton 1-4	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0	2100.0
Nanticoke 1-4	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0	1940.0
Nanticoke 5	531.0	531.0	531.0	531.0	531.0	531.0	531.0	531.0	531.0	531.0	531.0	531.0
Lennox 2	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0
Total Fossil-Steam Thermal	8816.0	8816.0	8816.0	8816.0	8807.0	8807.0	8807.0	8807.0	8807.0	8807.0	8816.0	8816.0
Combustion Turbines												
R.L. Hearn	22.0	22.0	21.0	19.0	17.0	17.0	17.0	17.0	17.0	19.0	21.0	22.0
Lakeview	22.0	22.0	21.0	19.0	17.0	17.0	17.0	17.0	17.0	19.0	21.0	22.0
J.C. Keith	7.0	7.0	7.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	7.0	7.0
Lambton	22.0	22.0	21.0	19.0	17.0	17.0	17.0	17.0	17.0	19.0	21.0	22.0
Sarnia-Scott 1-2	33.0	33.0	31.0	29.0	27.0	27.0	27.0	27.0	27.0	29.0	31.0	33.0
Sarnia-Scott 3-4	38.0	38.0	35.0	32.0	29.0	29.0	29.0	29.0	29.0	32.0	35.0	38.0
Detweiler	75.0	75.0	70.0	64.0	58.0	58.0	58.0	58.0	58.0	64.0	70.0	75.0
A.W. Manby	59.0	59.0	54.0	50.0	45.0	45.0	45.0	45.0	45.0	50.0	54.0	59.0
Nanticoke	22.0	22.0	21.0	19.0	17.0	17.0	17.0	17.0	17.0	19.0	21.0	22.0
Pickering A	46.0	46.0	42.0	38.0	34.0	34.0	34.0	34.0	34.0	38.0	42.0	46.0
Bruce A	42.0	42.0	41.0	38.0	32.0	32.0	32.0	32.0	32.0	38.0	41.0	42.0
Total Combustion Turbines	388.0	388.0	364.0	333.0	299.0	299.0	299.0	299.0	299.0	333.0	364.0	388.0

TABLE 2 - SHEET 4

ONTARIO HYDRO - EAST SYSTEM

1976 PEAK RESOURCES IN MW, ALL MONTHS

Purchases	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bryson	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Misc. NE Region	9.0	8.7	8.6	8.1	7.7	7.2	6.7	6.9	7.6	8.2	8.7	9.3
HQ Firm Power Pur.	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0
Total Purchases	1009.0	1008.7	1008.6	1008.1	1007.7	1007.2	1006.7	1006.9	1007.6	1008.2	1008.7	1009.3
East System Resources - Total												
With Dependable Hydraulic	18071.0	17927.7	18141.6	17556.1	17553.7	17614.2	17606.7	17602.9	17576.6	17571.2	18121.7	18074.3
With Median Hydraulic	18366.0	18354.7	18309.6	17962.1	18039.7	18093.2	18151.7	18103.9	18044.6	18024.2	18338.7	18334.3

TABLE 3 - SHEET 1

ONTARIO HYDRO - EAST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

Hydraulic - Dependable	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Abitibi Canyon	89	86	95	115	169	107	98	85	79	92	87	77	98
Barrett Chute	12	13	14	18	18	13	13	12	11	12	12	13	13
Chats Falls	35	33	36	64	60	53	39	30	29	34	35	36	40
Chenaux	44	39	47	87	66	71	55	42	40	48	47	47	53
Des Joachims	136	122	144	221	201	216	160	140	134	155	148	143	160
Harmon	14	16	14	36	141	76	36	25	26	25	29	25	39
Holden	68	62	68	101	104	104	77	76	73	84	77	72	81
Kipling	15	16	14	37	133	83	37	26	27	26	31	26	39
Little Long Rapids	13	14	13	33	125	74	33	23	24	24	28	23	36
Mountain Chute	12	13	13	17	17	13	13	12	12	12	12	13	13
Niagara, SAB + PGS - CNP	963	857	1065	890	931	936	903	893	886	870	1131	1057	949
Ontario Power	0	0	0	0	0	0	0	0	0	0	0	0	0
DeCew Falls	118	87	131	84	102	103	90	87	75	57	51	131	93
Otter Rapids	42	42	47	61	93	54	47	42	36	46	46	38	50
Aubrey Falls	13	9	16	9	11	11	12	11	11	8	10	13	11
Rayner - Wells	21	20	42	22	21	20	20	17	20	20	21	22	22
Red Rock Falls	12	10	21	14	17	12	12	10	10	11	12	13	13
Stewartville	12	13	14	20	20	14	14	11	11	11	12	14	14
Lower Notch	18	20	20	29	47	33	22	20	21	20	22	20	24
Robert H. Saunders	574	568	558	572	571	598	621	628	623	606	607	614	595
Georgian Bay	15	15	16	23	11	9	6	7	10	11	11	15	12
Bal. In EO Div.	27	25	31	41	38	23	16	17	18	18	21	28	25
Bal. In NE Region	33	32	33	44	38	35	31	26	23	31	32	31	32
Total All Plants	2286	2112	2452	2538	2934	2658	2355	2240	2199	2221	2482	2471	2412
Diversity	391	341	301	232	376	458	340	303	350	337	327	314	339
Total Hydraulic - Dependable	2677	2453	2753	2770	3310	3116	2695	2543	2549	2558	2809	2785	2751

TABLE 3 - SHEET 2

ONTARIO HYDRO - EAST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

Hydraulic - Median	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual*
Abitibi Canyon	128	134	146	224	224	219	157	131	146	151	156	128	162
Barrett Chute	26	30	40	50	51	34	17	18	18	19	21	24	29
Chats Falls	55	53	60	76	73	75	61	49	47	51	55	58	59
Chenaux	76	73	81	114	112	112	86	69	68	72	78	81	85
Des Joachims	234	227	243	336	350	343	246	218	222	230	244	242	261
Harmon	40	36	40	141	141	141	92	59	60	74	82	54	80
Holden	126	121	122	159	184	167	127	121	121	123	126	127	135
Kipling	41	37	42	139	139	141	97	63	65	82	89	56	83
Little Long Rapids	37	34	38	126	126	126	84	57	58	73	79	51	74
Mountain Chute	26	31	38	46	49	34	17	18	18	19	21	24	28
Niagara, SAB + PGS - CNP	1284	1276	1280	1109	1179	1186	1202	1161	1134	1131	1287	1287	1210
Ontario Power	68	34	50	37	42	42	42	42	45	45	85	90	52
DeCew Falls	131	131	131	131	131	131	131	131	131	131	131	131	131
Otter Rapids	62	64	69	129	175	113	79	66	72	79	80	64	88
Aubrey Falls	21	19	22	9	26	24	24	16	16	16	20	24	20
Rayner - Wells	33	30	67	46	50	52	44	29	29	28	42	43	41
Red Rock Falls	18	16	32	35	36	32	24	16	16	15	23	23	24
Stewartville	26	30	41	57	55	36	18	18	17	19	22	25	30
Lower Notch	30	32	36	68	107	61	38	28	28	30	34	35	44
Robert H. Saunders	636	656	674	735	750	752	760	771	748	730	696	679	716
Georgian Bay	25	26	28	28	29	23	17	15	14	16	22	26	20
Bal. in EO Div.	48	49	49	46	45	43	29	27	30	31	40	48	40
Bal. in NE Region	43	45	52	55	53	51	46	39	39	40	43	43	46
Total All Plants	3214	3184	3381	3896	4127	3938	3438	3162	3142	3205	3476	3363	3458
Diversity	-57	27	30	-112	14	-55	0	-52	69	37	0	23	-76
Total Hydraulic - Median	3157	3211	3411	3784	4141	3883	3438	3110	3211	3242	3476	3386	3382

* Annual Energy shown is the average of the arithmetic sum of the monthly energies.

TABLE 3 - SHEET 3

ONTARIO HYDRO - EAST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

Nuclear Thermal	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual*
Douglas Point	82	82	82	82	82	82	82	82	82	82	82	82	82
NPD	22	22	22	22	22	22	22	22	22	22	22	22	22
Pickering 1-4	2056	2056	2056	2056	2056	2056	2056	2056	2056	2056	2056	2056	2056
Total Nuclear Thermal	2160	2160	2160	2160	2160	2160	2160	2160	2160	2160	2160	2160	2160
Fossil-Steam Thermal													
R.L. Hearn 1-4													
R.L. Hearn 5	1144	1144	1144	1144	1147	1147	1147	1147	1147	1147	1144	1144	1146
R.L. Hearn 6-8													
J.C. Keith 1-4	254	254	254	254	254	254	254	254	254	254	254	254	254
Lakeview 1-2													
Lakeview 3-6	2278	2278	2278	2278	2278	2278	2278	2278	2278	2278	2278	2278	2278
Lakeview 7-8													
Lambton 1-4	980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980	1980
Nanticoke 1-4	1940	1940	1940	1940	1940	1940	1940	1940	1940	1940	1940	1940	1940
Nanticoke 5	485	485	485	485	485	485	485	485	485	485	485	485	485
Lennox 2	495	495	495	495	495	495	495	495	495	495	495	495	495
Total Fossil-Steam Thermal	8576	8576	8576	8576	8579	8579	8579	8579	8579	8579	8576	8576	8578
Combustion Turbines													
R.L. Hearn	20	20	19	19	17	17	16	16	17	18	19	20	18
Lakeview	20	20	19	19	17	17	16	16	17	18	19	20	18
J.C. Keith	7	7	6	6	6	6	5	5	6	6	6	7	6
Lambton	20	20	19	19	17	17	16	16	17	18	19	20	18
Nanticoke	20	20	19	19	17	17	16	16	17	18	19	20	18
Sarnia-Scott	68	68	66	61	56	56	56	56	56	60	64	67	61
Detweiler	73	73	70	64	58	58	58	58	58	64	69	72	65
A.W. Manby	57	57	53	48	45	45	45	45	45	48	53	56	50
Pickering A	40	40	39	38	34	34	32	32	34	36	39	40	37
Bruce A	38	38	37	36	30	30	30	30	30	36	37	38	34
Total Combustion Turbines	363	363	347	329	297	297	290	290	297	322	344	360	325

* Annual Energy shown is the average of the arithmetic sum of the monthly energies.

TABLE 3 - SHEET 4

ONTARIO HYDRO - EAST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

Purchases	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual*
Bryson				-1	-1	-1			-1	-1		-1	-1
Misc. NE Region	5	5	5	5	5	4	4	4	5	5	5	6	5
HQ Firm Power	900	900	900	900	900	900	900	900	900	900	900	900	900
Total Purchases	905	905	905	904	904	903	904	904	904	904	905	905	904
East System Resources - Total													
With Dependable Hydraulic	14681	14457	14741	14739	15250	15055	14628	14476	14489	14523	14794	14786	14718
With Median Hydraulic	15161	15215	15399	15753	16081	15822	15371	15043	15151	15207	15461	15387	15349

* Annual Energy shown is the average of the arithmetic sum of the monthly energies.

TABLE 4 - SHEET 1

ONTARIO HYDRO - EAST SYSTEM
1976 AUGUST, DECEMBER AND ANNUAL DATA
AND MOST FREQUENT MODES OF OPERATION

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)			
		MONTH OF AUGUST ENERGY				MONTH OF DECEMBER ENERGY				ANNUAL ENERGY			MOST FREQUENT MODES OF OPERATION IN 1976			
	PEAK Depend-able Mw.	Depend-able Av. Mw.	Median Av. Mw.	CAPACITY FACTOR ((3)÷(2)) %	PEAK Depend-able Mw.	Depend-able Av. Mw.	Median Av. Mw.	CAPACITY FACTOR ((7)÷(6)) %	PEAK December Dependable Mw.	Depend-able Av. Mw.	Median Av. Mw.	CAPACITY FACTOR ((11)÷(10)) %	B	I	P	R
Hydraulic Resources																
Abitibi Canyon	226	85	131	37.6	226	77	128	34.1	226	98	162	43.4	x	x		
Barrett Chute	172	12	18	7.0	172	13	24	7.6	172	13	29	7.6			x	x
Chats Falls	82	30	49	36.6	73	36	58	49.3	73	40	59	54.8	x	x		
Chenaux	116	42	69	36.2	108	47	81	43.5	108	53	85	49.1	x	x		
Des Joachims	372	140	218	37.6	367	143	242	39.0	367	160	261	43.6	x	x		
Harmon	125	25	59	20.0	125	25	54	20.0	125	39	80	31.2		x	x	
Holden	203	76	121	37.4	193	72	127	37.3	193	81	135	42.0	x	x		
Kipling	142	26	63	18.3	142	26	56	18.3	142	39	83	27.5		x	x	
Little Long Rapids	125	23	57	18.4	125	23	51	18.4	125	36	74	28.8		x	x	
Mountain Chute	166	12	18	7.2	164	13	24	7.9	164	13	28	7.9			x	x
Niagara SAB+PGS-CNP	1343	893	1161	66.5	1745	1057	1287	60.6	1745	949	1210	54.4	x	x	x	
Ontario Power	0	0	42	0	0	0	90	0	0	0	52	0	x	x		
DeCew Falls	155	87	131	56.1	155	131	131	84.5	155	93	131	60.0	x	x		
Otter Rapids	176	42	66	23.9	177	38	64	21.5	177	50	88	28.2		x	x	
Aubrey Falls	158	11	16	7.0	158	13	24	8.2	158	11	20	7.0			x	x
Rayner-Wells	275	17	29	6.2	275	22	43	8.0	275	22	41	8.0			x	x
Red Rock Falls	40	10	16	25.0	40	13	23	32.5	40	13	24	32.5		x	x	x
Stewartville	169	11	18	6.5	168	14	25	8.3	168	14	30	8.3			x	x
Lower Notch	260	20	28	7.7	252	20	35	7.9	252	24	44	9.5			x	x
Robert H. Saunders	716	628	771	87.7	696	614	679	88.2	696	595	716	85.5	x		x	
Georgian Bay	30	7	15	23.3	29	15	26	51.7	29	12	20	41.4		x	x	
Bal. in EO Division	51	17	27	33.3	50	28	48	56.0	50	25	40	50.0		x	x	
Bal. in NE Region	59	26	39	44.1	58	31	43	53.4	58	32	46	55.2	x	x		
TOTAL ALL PLANTS	5161	2240	3162	43.4	5498	2471	3363	44.9	5498	2412	3458	43.9				
Diversity	45	303	-52		79	314	23		79	339	-76					
TOTAL HYDRAULIC	5206	2543	3110	48.8	5577	2785	3386	49.9	5577	2751	3382	49.3				
Nuclear Thermal																
Douglas Point	206	82	82	39.8	206	82	82	39.8	206	82	82	39.8	x			
NPD	22	22	22	100.0	22	22	22	100.0	22	22	22	100.0	x			
Pickering No 1-4	2056	2056	2056	100.0	2056	2056	2056	100.0	2056	2056	2056	100.0	x			
TOTAL NUCLEAR THERMAL	2284	2160	2160	94.6	2284	2160	2160	94.6	2284	2160	2160	94.6				

TABLE 4 - SHEET 2

ONTARIO HYDRO - EAST SYSTEM
1976 AUGUST, DECEMBER AND ANNUAL DATA
AND MOST FREQUENT MODES OF OPERATION

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)			
	PEAK Dependable Mw.	MONTH OF AUGUST ENERGY Dependable Av. Mw.	MONTH OF AUGUST ENERGY Median Av. Mw.	CAPACITY FACTOR ((3)÷(2)) %	PEAK Dependable Mw.	MONTH OF DECEMBER ENERGY Dependable Av. Mw.	MONTH OF DECEMBER ENERGY Median Av. Mw.	CAPACITY FACTOR ((7)÷(6)) %	PEAK December Dependable Mw.	ANNUAL ENERGY Dependable Av. Mw.	ANNUAL ENERGY Median Av. Mw.	CAPACITY FACTOR ((11)÷(10)) %	MOST FREQUENT MODES OF OPERATION IN 1976 B	I	P	R
Fossil-Steam Thermal																
R.L. Hearn 1-8	1187	1147	1147	96.6	1196	1144	1144	95.7	1196	1146	1146	95.8	x	x	x	x
J.C. Keith 1-4	256	254	254	99.2	256	254	254	99.2	256	254	254	99.2				x
Lakeview 1-8	2298	2278	2278	99.1	2298	2278	2278	99.1	2298	2278	2278	99.1	x	x		x
Lambton 1-4	2100	1980	1980	94.3	2100	1980	1980	94.3	2100	1980	1980	94.3	x	x		x
Nanticoke 1-4	1940	1940	1940	100.0	1940	1940	1940	100.0	1940	1940	1940	100.0	x			x
Nanticoke 5	531	485	485	91.3	531	485	485	91.3	531	485	485	91.3	x			x
Lennox 2	495	495	495	100.0	495	495	495	100.0	495	495	495	100.0	x	x		x
TOTAL FOSSIL-STEAM THERMAL	8807	8579	8579	97.4	8816	8576	8576	97.3	8816	8578	8578	97.3				
Combustion Turbines																
R.L. Hearn	17	16	16	94.1	22	20	20	90.9	22	18	18	81.8				x
Lakeview	17	16	16	94.1	22	20	20	90.9	22	18	18	81.8				x
J.C. Keith	6	5	5	83.3	7	7	7	100.0	7	6	6	85.7				x
Lambton	17	16	16	94.1	22	20	20	90.9	22	18	18	81.8				x
Nanticoke	17	16	16	94.1	22	20	20	90.9	22	18	18	81.8				x
Sarnia - Scott	56	56	56	100.0	71	67	67	94.4	71	61	61	85.9				x
Detweiler	58	58	58	100.0	75	72	72	96.0	75	65	65	86.7				x
A.W. Manby	45	45	45	100.0	59	56	56	94.9	59	50	50	84.7				x
Pickering "A"	34	32	32	94.1	46	40	40	87.0	46	37	37	80.4				x
Bruce "A"	32	30	30	93.8	42	38	38	90.5	42	34	34	80.9				x
TOTAL COMBUSTION TURBINES	299	290	290	97.0	388	360	360	92.8	388	325	325	83.8				
Purchases																
Bryson	0	0	0	0	0	-1	-1	0	0	-1	-1	0				
Misc NE Region	7	4	4	57.1	9	6	6	66.7	9	5	5	55.6	x	x	x	
HQ Firm Power	1000	900	900	90.0	1000	900	900	90.0	1000	900	900	90.0	x			
TOTAL PURCHASES	1007	904	904	89.8	1009	905	905	89.7	1009	904	904	89.6				
TOTAL EAST SYSTEM RESOURCES	17603	14476	15043	82.2	18074	14786	15387	81.8	18074	14718	15349	81.4				

Notes: a) Peak and Energy shown are based on the definitions given in Table 1
b) B = Base Mode, I = Intermediate Mode, P = Peak Mode, R = Reserve Mode
c) Annual Dependable or Median Energy shown is the average of the arithmetic sum of the monthly dependable or median energies

TABLE 5 - Sheet 1

ONTARIO HYDRO - WEST SYSTEM

1976 PEAK RESOURCES IN MW, ALL MONTHS

Hydraulic - Dependable	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Aguasabon	43.4	41.7	41.4	42.1	44.4	45.0	45.0	44.9	45.0	45.0	45.0	45.0
Alexander	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4
Cameron Falls	74.9	74.4	74.4	74.4	74.4	74.4	74.4	74.6	75.1	75.1	75.1	75.0
Silver Falls	45.5	45.4	45.2	45.2	45.3	45.7	45.8	45.8	45.8	45.8	45.8	45.7
Caribou Falls	72.5	73.2	72.8	71.6	65.5	57.5	61.2	66.1	69.4	66.6	68.3	70.5
Ear Falls	10.8	10.2	9.4	9.1	9.9	10.8	12.1	12.5	12.5	11.2	11.2	11.1
Kakabeka Falls	18.3	18.0	19.2	18.4	22.3	19.9	17.7	16.9	16.9	17.7	18.5	18.6
Manitou Falls	59.6	59.4	59.7	59.5	59.4	53.6	58.9	59.7	59.5	59.7	59.5	59.6
Pine Portage	114.8	114.5	114.2	114.2	115.2	116.1	116.3	116.3	116.1	115.6	115.0	114.8
Whitedog Falls	50.4	51.0	50.7	49.7	45.6	39.1	42.9	46.0	47.9	47.2	47.4	49.0
Total All Plants	552.6	550.2	549.4	546.6	544.4	524.5	536.7	545.2	550.6	546.3	548.2	551.7
Diversity	23.9	22.8	23.0	25.2	22.8	23.0	28.1	32.7	28.9	29.5	26.5	27.0
Total Hydraulic - Dependable	576.5	573.0	572.4	571.8	567.2	547.5	564.8	577.9	579.5	575.8	574.7	578.7

TABLE 5 - Sheet 2

ONTARIO HYDRO - WEST SYSTEM

1976 PEAK RESOURCES IN MW, ALL MONTHS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hydraulic - Median												
Aguasabon	45.3	45.1	44.4	44.0	44.7	45.2	45.2	45.2	45.2	45.2	45.2	45.2
Alexander	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4	62.4
Cameron Falls	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6
Silver Falls	46.5	46.1	45.7	45.7	46.4	47.0	47.2	47.1	47.0	46.9	46.9	46.8
Caribou Falls	76,8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8
Ear Falls	17.1	15.8	15.2	14.1	15.5	17.3	18.7	19.4	19.2	18.7	18.2	17.8
Kakabeka Falls	23.6	23.8	24.0	23.9	23.9	23.8	23.7	23.1	22.9	23.3	23.2	23.6
Manitou Falls	63.0	63.4	64.9	66.2	66.0	65.4	65.4	65.7	65.7	65.5	65.0	63.9
Pine Portage	126.8	126.3	125.2	123.6	125.3	127.8	128.9	129.3	128.9	128.0	127.4	127.2
Whitedog Falls	60.0	60.0	60.0	60.0	60.0	58.6	58.5	60.0	60.0	60.0	60.0	60.0
Total All Plants	597.1	595.3	594.2	592.3	596.6	599.9	602.4	604.6	603.7	602.4	600.7	599.3
Diversity	-3.4	-4.8	-3.6	-1.5	-4.1	-7.3	-7.5	-4.2	-3.3	-1.9	-2.9	-3.3
Total Hydraulic - Median	593.7	590.5	590.6	590.8	592.5	592.6	594.9	600.4	600.4	600.5	597.8	596.0
Nuclear Thermal												
No Nuclear Unit	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Nuclear Thermal	.0	.0	.0	0	.0	.0	.0	.0	.0	.0	.0	.0
Fossil-Steam Thermal												
Thunder Bay	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0
Total Fossil-Steam Thermal	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0
Combustion Turbines												
Thunder Bay	29.0	29.0	28.0	27.0	25.0	25.0	25.0	25.0	25.0	27.0	28.0	29.0
Total Combustion Turbines	29.0	29.0	28.0	27.0	25.0	25.0	25.0	25.0	25.0	27.0	28.0	29.0
Purchases												
Manitoba Hydro	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Total Purchases	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
West System Resources Total												
With Dependable Hydraulic	902.5	899.0	897.4	895.8	889.2	869.5	886.8	899.9	901.5	899.8	899.7	904.7
With Median Hydraulic	919.7	916.5	915.6	914.8	914.5	914.6	916.9	922.4	922.4	924.5	922.8	922.0

TABLE 6 - Sheet 1

ONTARIO HYDRO - WEST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Annual*
Hydraulic - Dependable													
Aguasabon													
Alexander													
Cameron Falls													
Silver Falls													
Caribou Falls													
Ear Falls													
Kakabeka Falls		Monthly data not available on a station basis.											
Manitou Falls													
Pine Portage													
Whitedog Falls													
Total All Plants													
Diversity													
Total Hydraulic Dependable	325	325	325	325	325	325	325	325	325	325	325	325	325

*The annual energy is that which can be provided over a year consisting of 12 consecutive months from April 1 to March 31. Because of the large hydraulic storages available, it is assumed that this annual output is available each month.

TABLE 6 - Sheet 2

ONTARIO HYDRO - WEST SYSTEM

1976 ENERGY RESOURCES IN AVERAGE MW, ALL MONTHS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	*Annual
Hydraulic - Median													
Aguasabon													
Alexander													
Cameron Falls													
Silver Falls													
Caribou Falls													
Ear Falls													
Kakabeka Falls													
Manitou Falls													
Pine Portage													
Whitedog Falls													
Total All Plants													
Diversity													
Total Hydraulic - Median	468	468	468	468	.468	468	468	468	468	468	468	468	468
Fossil-Steam Thermal													
Thunder Bay	93	93	93	93	93	93	93	93	93	93	93	93	93
Total Fossil-Steam Thermal	93	93	93	93	93	93	93	93	93	93	93	93	93
Combustion Turbines													
Thunder Bay	28	27	26	25	25	24	24	24	25	26	26	27	26
Total Combustion Turbines	28	27	26	25	25	24	24	24	25	26	26	27	26
Purchases													
Manitoba Hydro	160	160	160	160	160	160	160	160	160	160	160	160	160
Total Purchases	160	160	160	160	160	160	160	160	160	160	160	160	160
WEST SYSTEM TOTAL RESOURCES													
With Dependable Hydraulic	606	605	604	603	603	602	602	602	603	604	604	605	604
With Median Hydraulic	749	748	747	746	746	745	745	745	746	747	747	748	747

TABLE 7

ONTARIO HYDRO - WEST SYSTEM

1976 AUGUST, DECEMBER AND ANNUAL DATA

AND MOST FREQUENT MODES OF OPERATION

WEST SYSTEM	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)			
	MONTH OF AUGUST				MONTH OF DECEMBER				ANNUAL				Most Frequent Modes of Operation in 1976			
		Energy				Energy				Energy						
(1)	Peak Dependable MW	Dependable Avg.MW	Median Avg.MW	Capacity Factor (3) ÷ (2) %	Peak Dependable MW	Dependable Avg.MW	Median Avg.MW	Capacity Factor (7)÷(6) %	Peak December Dependable MW	Dependable Avg.MW	Median Avg.MW	Capacity Factor (11)÷(10) %	B	I	P	R
HYDRAULIC RESOURCES																
Aguasabon	44.9				45.0				45.0				x	x		
Alexander	62.4				62.4				62.4				x	x		
Cameron Falls	74.6				75.0				75.0				x	x		
Silver Falls	45.8				45.7				45.7					x	x	
Caribou Falls	66.1				70.5				70.5				x	x		
Ear Falls	12.5				11.1				11.1				x	x		
Kakabeka Falls	16.9				18.6				18.6				x	x	x	
Manitou Falls	59.7				59.6				59.6				x	x	x	
Pine Portage	116.3				114.8				114.8				x	x		
Whitedog Falls	46.0				49.0				49.0				x	x		
Total All Plants	545.2				551.7				551.7				x	x		
Diversity	32.7				27.0				27.0							
TOTAL HYDRAULIC	577.9	325	468	56.2	578.7	325	468	56.2	578.7	325	468	56.2				
FOSSIL-STEAM THERMAL																
Thunder Bay	97.0	93	93	95.9	97.0	93	93	95.9	97.0	93	93	95.9				x
TOTAL FOSSIL-STEAM THERMAL	97.0	93	93	95.9	97.0	93	93	95.9	97.0	93	93	95.9				
COMBUSTION TURBINES																
Thunder Bay	25.0	24	24	96.0	29.0	27	27	93.1	29.0	26	26	89.7				x
TOTAL COMBUSTION TURBINES	25.0	24	24	96.0	29.0	27	27	93.1	29.0	26	26	89.7				
Purchases																
Manitoba Hydro	200.0	160	160	80.0	200.0	160	160	80.0	200.0	160	160	80.0	x	x		
TOTAL PURCHASES	200.0	160	160	80.0	200.0	160	160	80.0	200.0	160	160	80.0				
TOTAL WEST SYSTEM RESOURCES	899.9	602	745	66.9	904.7	605	748	66.9	904.7	604	747	66.8				

Notes:
a) Peak and Energy shown are based on the definitions given in Table 5-C-1.
b) B = Base Mode, I = Intermediate Mode, P = Peak Mode, R = Reserve Mode.
c) Annual Dependable or Median Energy shown is the average of the arithmetic sum of 12 monthly dependable or median energies starting April 1 of the year shown.

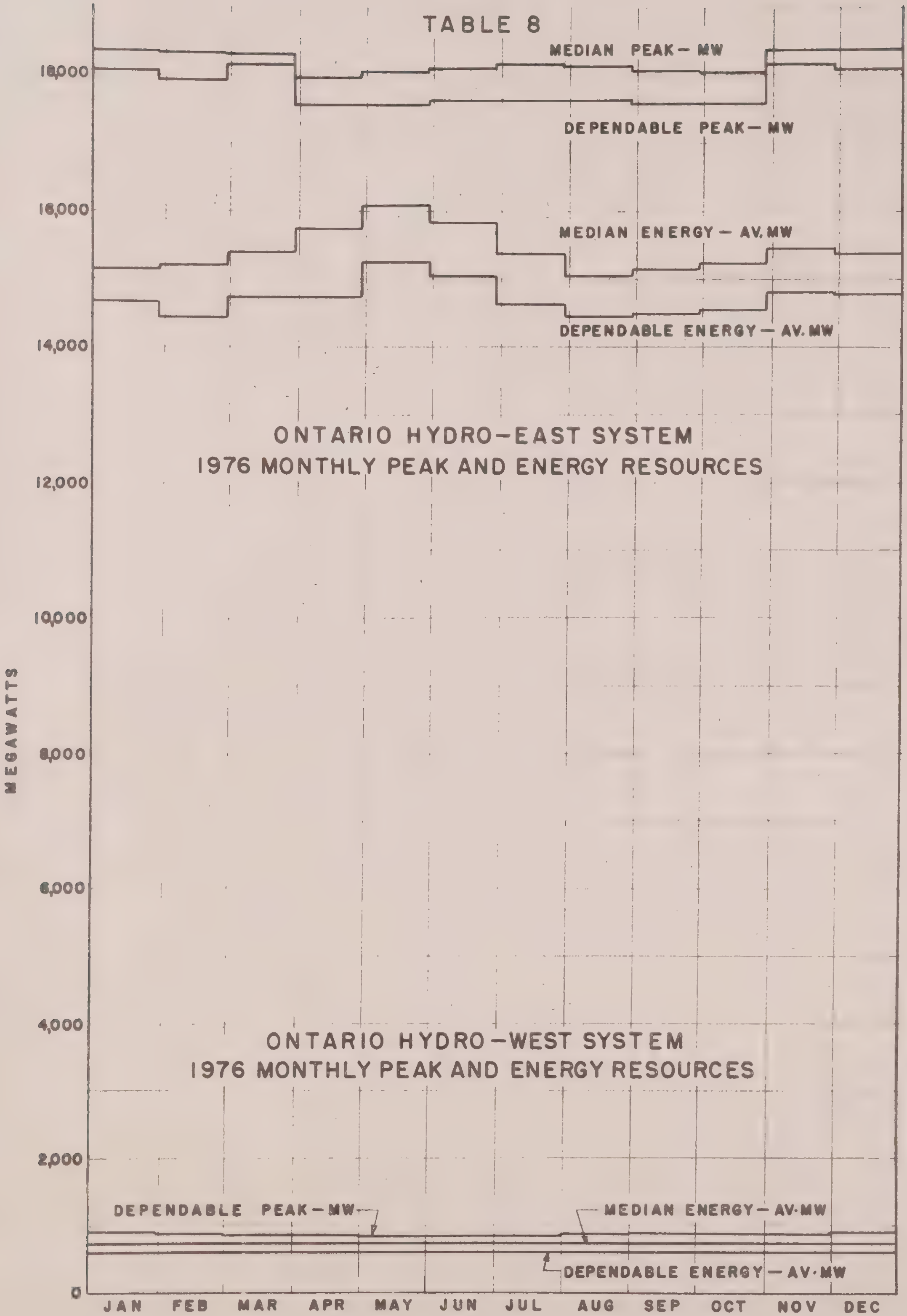


TABLE 8
MEDIAN PEAK - MW
DEPENDABLE PEAK - MW
MEDIAN ENERGY - AV. MW
DEPENDABLE ENERGY - AV. MW
ONTARIO HYDRO-EAST SYSTEM
1976 MONTHLY PEAK AND ENERGY RESOURCES
ONTARIO HYDRO-WEST SYSTEM
1976 MONTHLY PEAK AND ENERGY RESOURCES
DEPENDABLE PEAK - MW
MEDIAN ENERGY - AV·MW
DEPENDABLE ENERGY - AV·MW
MEGAWATTS
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC

APPENDIX 7-A

Voltage Levels on the Ontario Hydro System

This Appendix lists the current standard voltage levels used by Ontario Hydro, and gives a brief account of why the extra-high voltage (EHV) level of 500 kV was chosen.

The electric utility industry has standardized on a limited number of voltage levels. Such standardization allows the use of standardized designs of equipment and results in lower costs and improved reliability. It also permits operating experience and reliability data to be shared among utilities. For each standard voltage level there is a nominal voltage specified for identification purposes. The standards then specify for each voltage class the range of operating voltages for which the equipment should be designed, the maximum transient overvoltages which the equipment must be able to withstand, and other limits which assist the planner and designer in designing a reliable and cost-effective transmission system.

There are a number of national and international standardizing bodies throughout the world, and standards in different countries differ somewhat from one another. Most equipment bought by Ontario Hydro is specified to be in accordance with the standards of either the Canadian Standards Association (CSA) or the American National Standards Institute (ANSI).

Ontario Hydro has standardized on the following nominal voltage levels, which are quoted below in kV

Bulk Power Transmission:	500, 230, 115
Area Supply Transmission:	230, 115
Subtransmission:	44, 27.6, 22, 13.8
Distribution:	27.6, 13.8, 12.48, 8.32, 4.16, 0.600, 0.120/0.240 0.120/0.208

There are other standard voltage levels recognized by CSA or ANSI, but not used extensively by Ontario Hydro, such as 765, 345, 138, 34.5, 0.480.

Planning studies to establish a voltage level for incorporating generation on the Moose River System, some 240 miles north of Sudbury, were begun in the late 1950's. At that time 230 kV was Ontario Hydro's highest standard voltage, 345 kV had been in use in the United States and 460 kV was being considered for use there. The alternative voltage levels of 345, 400 and 460 kV were considered for incorporating the Moose River generation. These studies showed that 400 and 460 kV were equal in cost and both were superior to 345 kV. The higher level of 460 kV was chosen on the basis of intangibles:

(a) It would have a greater margin of safety and stability.

(b) It was considered within the capabilities of North American manufacturers.

(c) It was more likely to become a North American Standard than 400 kV.

(d) It would be more useful in future in Southern Ontario.

In 1959 Ontario Hydro established a test project at Coldwater to obtain data needed for 460 kV line design. Considerable important research work was done at that project, particularly in regard to corona losses and radio interference.

When 500 kV nominal, 550 kV maximum was chosen as a national standard Ontario Hydro was able to uprate the 460 kV system to the new standard without major design changes.

Selection of an appropriate system voltage depends upon many factors but the principal factors are the amount of power to be transmitted and the distance the power is to be transmitted. In Ontario 80% of the load is located south of an east-west line running through Parry Sound and more than one third of the load is located in the Toronto-Hamilton area. The Great Lakes and their connecting rivers are relatively close to all the major load centres and it appears likely that in the future an average transmission distance from the generating stations to the load centres will be less than one hundred miles. This contrasts with the conditions in the Province of Quebec where the transmission distance to Montreal from the Manicouagan-Outardes complex is 360 miles, from the Churchill Falls development is 720 miles and from the James Bay development is about 600 miles.

Studies of future voltage levels made by system designers throughout the world have usually indicated that a new voltage level should be approximately double the existing highest transmission voltage. A voltage level of less than this does

not usually provide sufficient advantages to justify a change. On the other hand unless special circumstances are involved, the higher initial capital costs of a voltage level much greater than twice the existing level cannot usually be justified.

Figure 1 shows the approximate transmission capability of 765 kV, 500 kV and 230 kV circuits versus length. For the short lengths the figures are based on a current limit of 2500 amperes for 230 kV and 4000 amperes for 500 and 765 kV. These are the ampacity limits of station equipment such as switches, breakers, current transformers, etc, which are available from most major manufacturers. For the longer lengths the limits are based on stability and voltage considerations. The curves can be approximate only since the actual limit will be dependent on the detailed design parameters of the line, the system in which the line is to be located and the criteria which the system planner uses. The figure shows that for lengths of 250 miles the power transmitting capability of a 500 kV circuit is about 7-1/2 times that of a 230 kV circuit and about 1/2 that of a 765 kV circuit. For short lengths, the power transmitting capability of a 500 kV circuit is about 3-1/2 times that of a 230 kV circuit and about 2/3 that of a 765 kV circuit.

Figure 2 shows the initial capital investment required for 230 kV, 500 kV and 765 kV single and multiple circuit lines, 100 miles long. Figure 3 shows how the initial cost per megawatt-mile of transmitted power varies with distance for the three voltage levels. Figure 3 indicates that there is a significant cost saving in using a 500 kV or 765 kV voltage level on the assumption that the circuits are loaded to their capability. The differences shown in Figure 3 between 500 kV and 765 kV lines are not large enough to show a strong preference for either voltage. Greater differences might occur in the study of a specific facility where all the design parameters could be carefully selected to reduce costs.

The following table shows how the 3 voltage levels compare in the use of land. The 500 kV and 765 kV levels are some 2 to 8 times more efficient per MW of transmitted power than 230 kV when comparing the area used by the tower base. For this factor, the 500 kV line is the most efficient of the towers considered. When compared on the basis of area of right of way the 500 kV and 765 kV towers are up to 3 times more efficient than a 230 kV line. The comparison does not include 765 kV 2-circuit towers because such towers would be extremely massive and costly and are unlikely to be used in the early stage of developing a 765 kV system. As far as we know, all 765 kV systems existing or being designed use 1-circuit towers.

Comparison of Land Use

Voltage kV	Type of Tower	Right of Way Width Ft.	Area for 100 Mi: Right of Way Acres	Area for 100 Mi: Tower Base Acres	Area for 100 Mi per MW: Right of Way Acres	Area for 100 Mi per MW: Tower Base Acres
230	2-cct	110	1333	11.88	2.09	0.0186
	4-cct	130	1576	14.56	1.24	0.0114
500	1-cct	220	2667	5.58	1.06	0.0022
	2-cct	250	3030	11.88	0.615	0.0024
765	1-cct	310	3758	25.47	0.759	0.0051

The transmission criteria adopted by the Northeast Power Coordinating Council, of which Ontario Hydro is a member, require that a system be designed with sufficient transmission to maintain stability with one circuit out of service and subsequent loss of a tower line (1-circuit or 2-circuit). The criteria also require that for normal transfer the system be operated to maintain the stability of the interconnected power systems for loss of the most severe of a 1-circuit or 2-circuit line. For emergency transfers, the criteria require that the system be operated to maintain stability for loss of one circuit. Application of these criteria, results in the capabilities for short lines (i.e. up to 50 miles) shown in Figure 4.

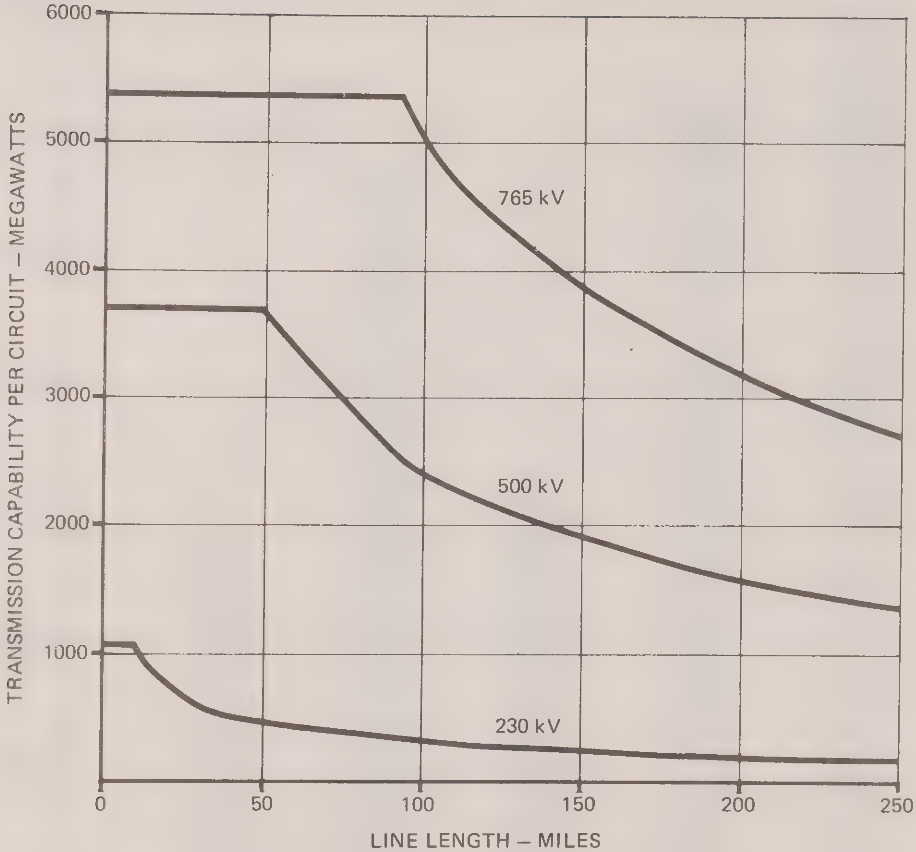
Figure 4 shows that if the objective is to obtain the highest power transmitting capability while minimizing the number of rights of way and lines the the 500 kV, 2-circuit line is significantly better than the 230 kV 2-circuit and 4-circuit and 500 kV and 765 kV 1-circuit lines.

Based on the foregoing considerations, Ontario Hydro concluded that 500 kV is the appropriate voltage level for the future bulk power transmission network because:

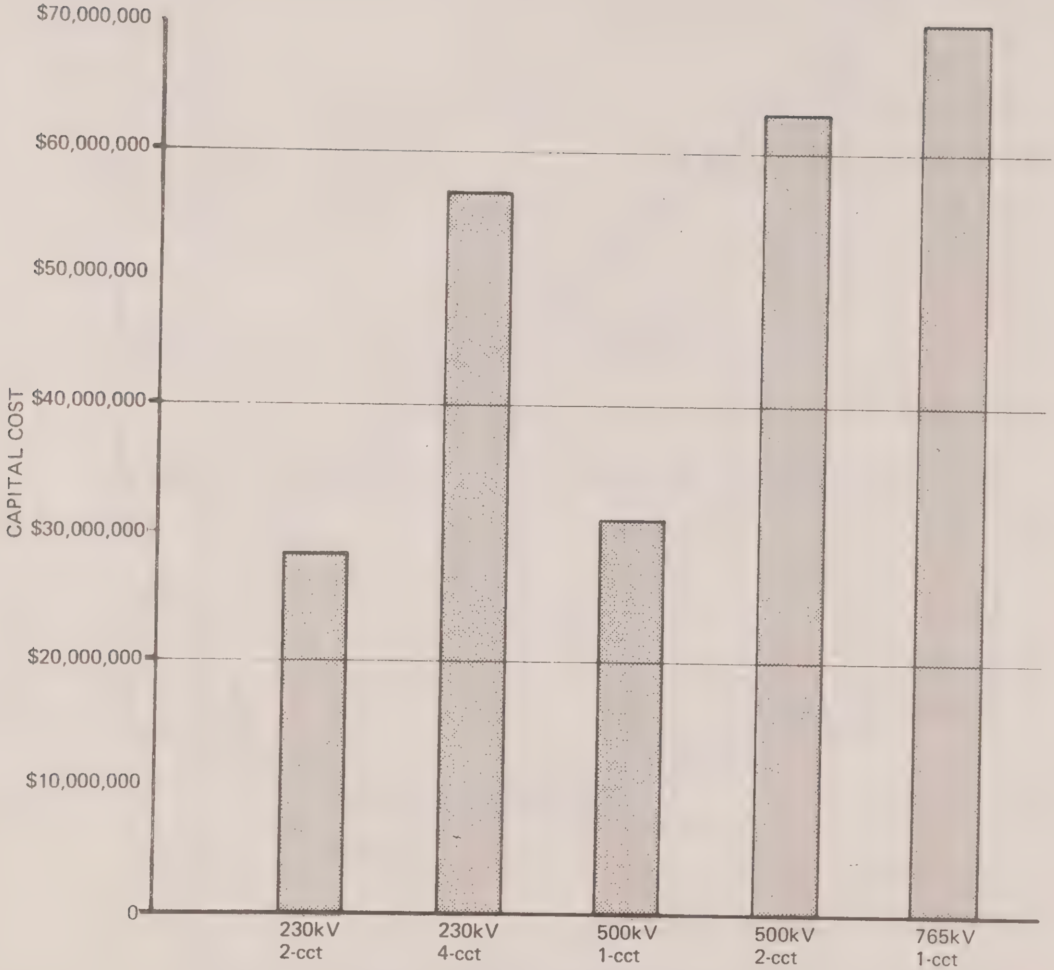
(1) There is a satisfactory balance between the cost of construction, land use and the future power requirements of the system.

(2) It matches the existing 500 kV system which was constructed for incorporating the Moose River system and for which Ontario Hydro has a great deal of successful design, operating and maintenance experience.

The choice between the use of 1-circuit 2-circuit 500 kV lines is made after considering the factors relevant to such lines.

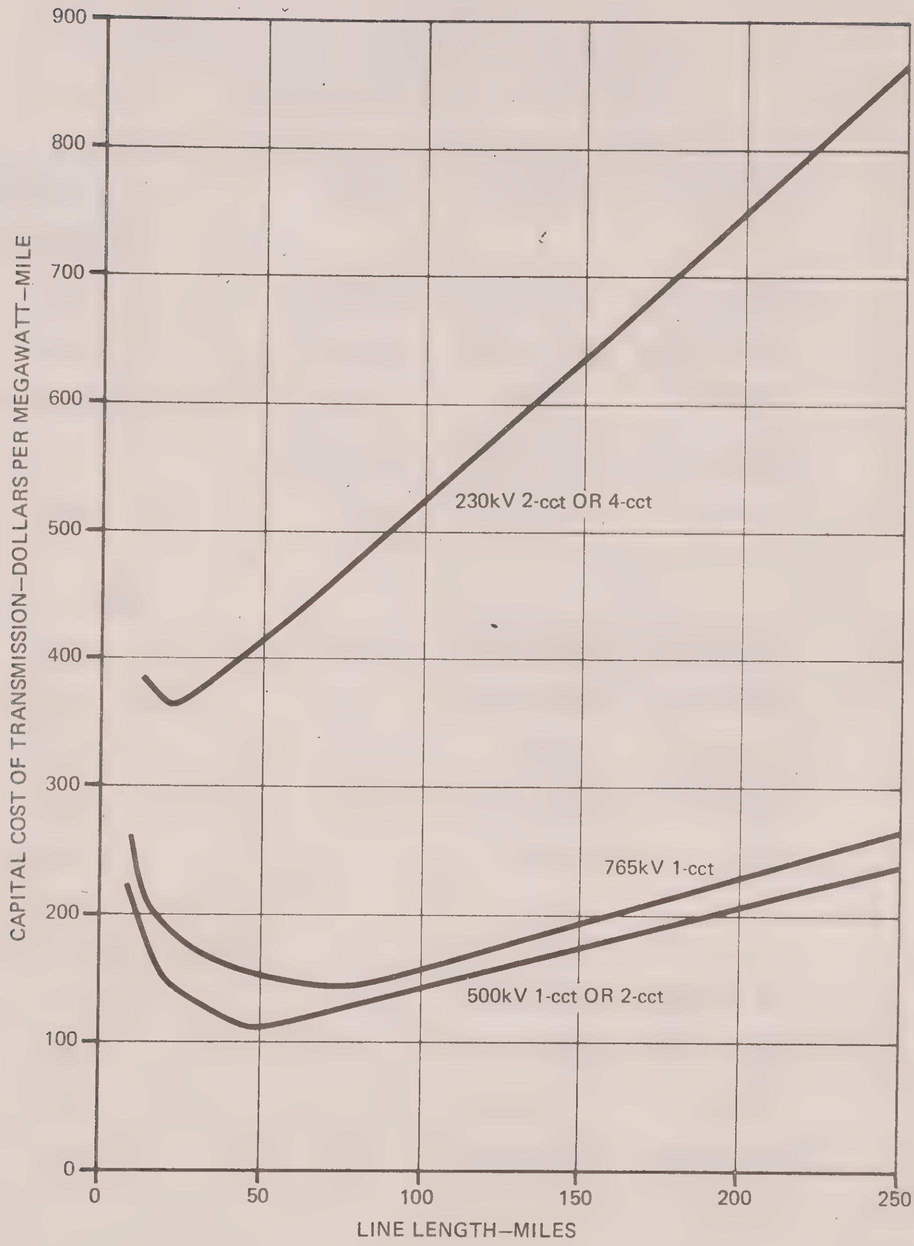


POWER TRANSMISSION CAPABILITY
VS
DISTANCE



CAPITAL COST OF TRANSMISSION
100 MILES OF TOWER LINE
(INCLUDING PROPERTY COSTS)

(1976 DOLLARS)



CAPITAL COST OF TRANSMISSION
LINES PER MEGAWATT—MILE
VS
DISTANCE

(INCLUDES TERMINAL COSTS)

APPENDIX 7—A

FIGURE 3

FIGURE 4

Firm Capacity in Megawatts
Line Length up to 50 Miles

Criterion and Tower Type	Number of Lines in Parallel 1	2	3
Loss of 1 cct			
230 kV 2 cct	470-1050	1410-3150	2350-5250
230 kV 4 cct	1410-3150	3290-7350	5170-11550
500 kV 1 cct	0	3700	7400
500 kV 2 cct	3600-3700	10800-11100	18000-18500
765 kV 1 cct	0	5380	10760
Loss of 1 Line			
230 kV 2 cct	0	940-2100	1880-4200
230 kV 4 cct	0	1880-4200	3760-8400
500 kV 1 cct	0	3700	7400
500 kV 2 cct	0	7200-7400	14400-14800
765 kV 1 cct	0	5380	10760
Loss of 1 cct + 1 Line			
230 kV 2 cct	0	470-1050	1410-3150
230 kV 4 cct	0	1410-3150	3290-7350
500 kV 1 cct	0	0	3700
500 kV 2 cct	0	3600-3700	10800-11100
765 kV 1 cct	0	0	5380

NORTHEAST POWER COORDINATING COUNCIL

BASIC CRITERIA FOR DESIGN AND OPERATION OF INTERCONNECTED POWER SYSTEMS

NORTHEAST POWER COORDINATING COUNCIL
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BASIC CRITERIA FOR DESIGN AND OPERATION OF INTERCONNECTED POWER SYSTEMS

Originally adopted by the members of the Northeast Power Coordinating Council, September 20, 1967. Revision adopted by the members of the Northeast Power Coordinating Council, July 31, 1970. Revision adopted by the members of the Northeast Power Coordinating Council, June 6, 1975.

C O N T E N T S

1. INTRODUCTION

The purpose of the Northeast Power Coordinating Council is to improve the reliability and efficiency of the interconnected power systems of its members through improved coordination in system design and operating procedures.

One of the steps in reaching this objective is the development of criteria that will be used in the design and operation of the major interconnected power systems. Definitions of several terms used in the following paragraphs are listed in the Appendix.

It is recognized that more rigid criteria will be applied in some segments of the Council area because of local considerations. It is also recognized that the basic criteria are not necessarily applicable to those elements of the individual members' systems that are not a major part of the interconnected transmission network.

The transmission criteria are applicable either to the areas (New Brunswick, New England, New York or Ontario) or to the entire Council interconnection in its relations with neighboring "pools".

An interconnected power system should be designed and operated at a level of reliability such that the loss of a major portion of the system would not result from reasonably foreseeable contingencies. In determining this reliability, it would be desirable to give consideration to all combinations of contingencies occurring more frequently than once in some stipulated number of years. However, sufficient data and techniques

are not available at the present time to define all the contingencies that could occur or to assess and rank their probability of occurrence. Therefore, it is proposed that the interconnected power systems be designed and operated to meet certain specific contingencies. Loss of small portions of the system (such as radial portions) may be tolerated, provided that these do not jeopardize the integrity of the over-all interconnected power systems.

The following criteria for design and operation of interconnected power systems define area generation and transmission requirements. In addition, criteria for determining inter-area transmission transfer capabilities are defined.

Two categories of transmission transfer capabilities are to be considered: normal and emergency. Normal conditions are to be assumed unless an emergency, as defined by Item 2 in the "List of Definitions", exists.

Design studies will assume applicable contractual transfers and the most severe expected load and generation conditions. Operating transfer capability studies will be based on the particular load and generation pattern expected to exist for the period under study. All reclosing facilities will be assumed in service unless it is known that such facilities have been rendered inoperative.

2. GENERATING CAPACITY

Generating capacity will be installed and located in such a manner that after the due allowance for required maintenance and expected forced outages, each area's generating supply will equal or exceed area load at least 99.9615 percent of the time. This is equivalent to a "loss-of-load probability of one day in ten years".

3. AREA TRANSMISSION REQUIREMENTS

The power system should be designed with sufficient transmission capacity to serve area loads under the conditions noted below. The power system should also be operated in such a manner that the design objectives are fulfilled.

3.1 Stability Conditions

Stability of the interconnected power systems shall be maintained during and after the most severe of the conditions stated in a, b, c, d, and e below. Also, the system must be adequate for testing of the outaged element as described in "a" through "e" by manual reclosing after the outage and before adjusting any generation. These requirements will also apply after any critical generator unit, transmission circuit, or transformer has already been lost, assuming that the area generation and power flows are adjusted between outages by use of Five-Minute Reserve.

a. A permanent three phase fault on any generator, transmission circuit, transformer or bus section, cleared in normal time, with due regard to reclosing facilities.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple transmission circuit tower, cleared in normal time, with due regard to reclosing facilities.

c. A permanent phase to ground fault on any generator, transmission circuit, transformer,

or bus section with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system or signal channel malfunction.

d. Loss of any element without a fault.

e. A permanent phase to ground fault on a circuit breaker, cleared in normal time, and with due regard to reclosing facilities.

3.2 Steady State Conditions

a. Voltages, line and equipment loadings shall be within normal limits for pre-disturbance conditions.

b. Voltages, line and equipment loadings shall be be within applicable emergency limits for the system load and generation conditions that exist following the disturbance specified in 3.1.

4. TRANSMISSION CAPABILITIES

Transfers of power from one area to another, as well as within areas, should be considered in the design of inter-area transmission and internal area facilities.

Operating capabilities shall be adhered to for normal transfers and transfers during emergencies. These capabilities will be based on the facilities in service at the time of the transfers. In determining the emergency transfer capabilities, it is assumed that a less conservative margin is justified.

Transmission transfer capabilities shall be determined under the following conditions:

4.1 Normal Transfers

4.1.1 Stability Conditions

Stability of the interconnected power systems shall be maintained during and after the most severe of the conditions stated in a, b, c, d, and e below. Also, the system must be adequate for testing of the outaged element as described in "a" through "e" by manual reclosing after the outage and before adjusting any generation.

a. A permanent three phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time, with due regard to reclosing facilities.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple transmission circuit tower, cleared in normal time, with due regard to reclosing facilities.

c. A permanent phase to ground fault on any generator, transmission circuit, transformer, or bus section with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system or signal channel malfunction.

d. Loss of any element without a fault.

e. A permanent phase to ground fault on a circuit breaker, cleared in normal time, and with due regard to reclosing facilities.

4.1.2 Steady State Conditions

a. For the facilities in service during the transfer, voltages, line and equipment loadings shall be within normal limits.

b. Voltages, line and equipment loadings shall be within applicable emergency limits for the system load and generation conditions that exist following the disturbance specified in 4.1.1.

4.2 Emergency Transfers

4.2.1 Stability Conditions

Stability of the interconnected systems shall be maintained during and after the most severe conditions in "a" and "b" below. System conditions may be adjusted before the outaged element as described in "a" and "b" below is tested.

a. A permanent three phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time and with due regard to reclosing facilities.

b. Loss of any element without a fault.

4.2.2 Steady State Conditions

a. For the facilities in service during the transfer, voltages, line and equipment loadings shall be within applicable emergency limits.

b. Voltages, line and equipment loadings shall

be within applicable emergency limits following the disturbance in 4.2.1.

5. POSSIBLE BUT IMPROBABLE CONTINGENCIES

Studies will be conducted to determine the effect of the following contingencies on system performance and plans will be developed to minimize the spread of any interruption that might result.

a. Loss of the entire capability of a generating station.

b. Loss of all lines emanating from a generating station, switching station or substation.

c. Loss of all transmission circuits on a common right-of-way.

d. Permanent three phase fault on any generator, transmission circuit, transformer, or bus section, with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system or signal channel malfunction.

e. The sudden dropping of a large load or major load center.

f. The effect of severe power swings arising from disturbances outside the Council's interconnected systems.

APPENDIX - LIST OF DEFINITIONS

1. AREA

An area is defined as either New Brunswick, New England, New York or Ontario.

2. EMERGENCY

An emergency is assumed to exist in an area if firm load may have to be dropped because sufficient power is unavailable in that area. Emergency transfers are applicable under such conditions.

3. APPLICABLE EMERGENCY LIMITS

These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitation, etc.

Short time emergency limits are those which can be utilized for at least five minutes.

The limiting condition for voltages should recognize that voltages at key locations should not drop below that required for suitable system stability performance, and should not adversely affect the operation of the interconnected systems.

The limiting condition for equipment loadings should be such that cascading will not occur due to operation of protective devices on the failure of facilities.

4. FIVE-MINUTE RESERVE

Five-Minute Reserve is that portion of unused generating capacity which is synchronized to the system, and is fully available within five minutes, plus that portion of capacity available in shut down generating units, in pumped hydro units and by curtailing interruptible loads which is fully available within five minutes.

5. "WITH DUE REGARD TO RECLOSING FACILITIES" is intended to mean that recognition will be given to the type of reclosing: i.e., manual or automatic, and the kind of protective schemes insofar as time is concerned.

6. ELEMENT

An element is defined as a generator, transmission circuit, transformer, circuit breaker or bus section.

Appendix 8-A

Transmission Line Construction and Right of Way Restoration and Management Practices

CONTENTS

Appendix 8-A

Transmission Line Construction and Right of Way Restoration and Management Practices

A. Construction Practices and Right of Way Restoration Practices

The major operations in the construction of overhead transmission lines include the selective cutting of the right of way; establishment of construction access routes; the installation of tower foundations; the assembly and erection of towers; the stringing of the conductor; the installation of counterpoise; and clean-up and restoration of the right of way. Construction may be carried out either by Hydro's in-house construction staff or by contract forces, and in either case will comply with the practices prescribed in "Protection of the Environment During Power Line Construction" (Reference 8A(1)).

The following is a brief description of the various construction operations:

(a) Right of Way Clearing

Selective cutting, and restoration is carried out as detailed in "Specification for the Selective Cutting and Restoration of new 500, 230, 115 and 44 kV Transmission Line Right of Way" (Reference 8A(2)).

In general, selective cutting is employed in areas with a lower percentage of forested land, such as in farming areas, and also in recreational and vacation areas that are used frequently by the general public. The minimum clearing of trees and shrubs is done at each tower location that is needed to assemble and erect the tower. Between tower locations, trees which come within a minimum distance of the conductor and would interfere with the safe efficient operation of the line are removed. Trees are also removed where necessary, to provide construction access routes to tower locations.

Where lines pass through heavily forested lands, such as in Northern Ontario, most of the trees on the right of way are cut. Tree screens are left at road crossings. In addition, water-crossings and other ecologically sensitive areas are treated in order to minimize the impact on the natural environment.

(b) Access Routes

In locating access routes, special care is taken to minimize damage to farmland, cutting of trees, potential erosion, and other environmental impacts. Aerial photography is used to identify

environmentally sensitive areas and infra-red photography is used to detect the location of field tile in farmland. On private property, access routes are determined in conjunction with the owner.

In farming areas existing road allowances and laneways are used where possible so that soil compaction on cultivated fields may be reduced. Also on cultivated lands, gravel roads are installed only where necessary to gain access to the tower sites. On completion of the work, the gravel is removed unless other arrangements are made with the owners. Farmland that has been compacted by construction traffic is chisel-ploughed so that it may be cultivated with conventional farm equipment.

(c) Foundations

The next stage in the construction program involves the installation of foundations to support the towers. The type of foundation to be installed at each tower location is dependent on the nature of the soil and the type of tower to be built. Soil tests are carried out as may be necessary at tower positions. In swamp locations and areas where the sub-soil is inadequate to support a tower with a normal-type foundation, the installation of piles may be necessary. Special towers, such as at angles in the line or at terminal positions, require extensive excavation and placement of large quantities of concrete. The majority of the foundations will require concrete, which is delivered to the sites by truck. Construction equipment such as augers, backhoes, trucks, compressors and other equipment items may be employed during the construction of the foundations. Excavated material is removed from the site or spread in a location suitable to the owner. Before starting work on the foundation top soil is removed and saved for reinstatement when the construction work is completed.

(d) Tower Assembly and Erection

Following the completion of the foundations, the next operation is the delivery of tower steel to each tower location in preparation for building the towers. The steel is transported from the material storage areas normally by truck. Although procedures are followed during this operation, as well as during the previous foundation operation, to minimize damage to fields and roads, a certain amount of damage is to be anticipated. This damage is repaired upon completion of the work, or appropriate compensation is paid to the land owner.

The individual steel members are assembled together to form sections of the tower which are laid out on the ground in a manner suitable for erection, which is normally done by means of a crane. In some cases, depending on the size of the tower, the tower is completely assembled on the ground and erected in one lift by a crane. If the location of the tower site is such that it is not accessible by crane, the tower may be erected by a gin pole. This is a single structural member supported in a vertical position by guy ropes and used to raise the tower sections. This method is very slow and very costly compared to the use of a crane and is therefore only used when crane access is impractical.

(e) Conductor Stringing

The installation of the line conductors is the next operation. The technique, which is now usually employed for this work, is known as "tension stringing" in which the conductors are pulled under tension through travellers (pulleys) attached to each tower. Being under tension, the conductors are kept off the ground at all times and thereby avoiding damage to objects underneath the conductors as well as to the conductors themselves. After insulator strings and travellers are hung on the towers, the first step in tension stringing is to install a light rope along the section of the line to be strung. These sections vary in length up to about 30,000 ft. A helicopter is used to fly this rope along the right of way for deposit in the travellers. This rope is then used to pull in larger ropes and steel cables until one of sufficient strength pulls through the conductors.

After all the conductors are pulled into place by this method, they are tightened to a specified tension. This tension ensures that the line maintains the correct ground clearance under all operating conditions. Following this, the conductors are clamped at each tower and damping devices are installed on the conductors to limit vibration. Where bundled conductors are used on higher voltage lines spacing devices must also be installed along the span between the towers. Ground cables, which are attached at the tower peak positions above the conductors, are strung in a similar manner.

Specialized equipment is required for this method of stringing, and it is moved from section to section along the right of way as the stringing proceeds. This method is effective in minimizing damage to the terrain as it avoids the need to move heavy equipment along the full length of the right of way and is compatible with selective cutting.

(f) Counterpoise

To ensure that the line will operate efficiently when in service, it is necessary that the electrical ground resistance at each tower be low. To accomplish this a ground electrode is installed at each tower. If, because of soil conditions, the ground resistance at many of the towers is too high, additional grounding must be installed. The normal procedure in this case is to bury two continuous wires along the right of way, one at each side of the towers. These wires are normally buried to a depth of 18" in cultivated ground and 8" in bush areas and in rocky ground. The wires are installed by a tractor which carries the ground wire on reels and buries the wire as it proceeds down the right of way by means of a plow attachment. The wires are then connected to each tower. An efficient grounding system on a transmission line minimizes the chance of operational outages due to lightning.

(g) Clean-up and Restoration

The final stage of construction is the clean-up of the right of way to be sure that all construction materials are removed. This is an ongoing procedure during the construction of the line, but a final clean-up is also carried out. Any necessary repairs to fences, fields and roads are completed. Grading, if required, at the tower sites is also completed in preparation for further restoration.

After the construction clean-up is completed, a program of restoration is carried out to bring the right-of-way or station site to the optimum state possible. Restoration of disturbed areas, outside of cultivated land, is carried out by seeding with compatible grasses or legumes to retard weed growth and to help to prevent erosion. Trees may be planted at suitable locations such as road and water crossings, pond and spring areas where residual trees were removed or additional trees are required.

B. Right of Way and Transmission Line Management Practices

B.1 Right of Way Land and Vegetation Management

Once located and established, transmission lines and their associated right of way are maintained and managed as required by the Corporation's safety, reliability, economic and good citizenship standards. This includes not only the control of vegetation (brush and trees) that is incompatible with overhead power lines, but also such activities as the protection of ecologically sensitive areas, the establishment and monitoring of multi-use projects (parks, wildlife habitat, recreation areas) and landscaping and grounds maintenance.

The Corporation recognizes the need for a qualified field staff capable of implementing such policies and has recruited and trained accordingly.

Right of way land and vegetation management activities fall within four general categories:

(a) Tree Pruning and Removal

To prevent power failures, and to ensure the safety of the public and maintenance employees alike, trees must not be allowed to come closer than a specified distance to energized apparatus. This distance varies with the voltage of the line. In order to minimize the visual and environmental impact of the line, the vegetation that remains following the selective cutting and restoration of the rights of way must be carefully managed.

To accomplish the above aims, foot patrols are carried out at least once every two years on high voltage rights of way in order to identify potentially dangerous tree conditions. Tree pruning and removal work is done on a two to three year cycle basis by trained Hydro foresters using modern equipment and techniques.

(b) Brush Control

Incompatible, fast growing woody vegetation (brush) must be controlled for the same reasons as trees. This is done on an average of every five to eight years depending on growth rates and locations.

Control is achieved by cutting, by the selective use of government approved herbicides, by biological control methods or by combinations of these techniques. Biological control consists of the establishment and/or encouragement of vigorous low growing compatible vegetation, such as grasses,

legumes and shrubs, which provide competition for seedlings of tree species. Herbicide application is supervised by licenced personnel, and is done in accordance with federal and provincial legislation.

(c) Landscaping, Grounds Maintenance and Weed Control

Landscaping and grounds maintenance activities ensure that Corporation properties are designed and maintained to a standard that is compatible with the surrounding community. Weed control programs are carried out to comply with the regulations of the provincial Weed Control Act.

(d) Ecologically Sensitive Areas

It is possible that some areas along rights of way may be designated as having provincial or regional ecological significance. Other areas may have a more localized significance, but still require special management treatment. An example of such areas would be wetlands and other areas where the risk of stream sedimentation or soil erosion is evident.

Mitigation and management practices include the stability of the hydrologic cycle in wetlands, the maintenance of stream temperature in cold-water streams, the planting of ground covers such as grasses, legumes and shrubs, to prevent or rectify erosion, the proper installation and maintenance of culverts and the judicious use of herbicides, mechanical cutting and biological control in appropriate situations.

Some rights of way are managed to sustain or attract wildlife. Some are managed to limit access, thus avoiding excessive traffic where such traffic could be detrimental to a sensitive environment.

B.2 Transmission Line Maintenance

Three categories of maintenance have been established for the transmission system. These are as follows:

(a) Running Maintenance

Routine

These are planned repairs of a localized nature which have to be carried out occasionally and are usually of one-half to one-day duration.

These repairs could require the moving in of trucks and there is the possibility of crop damage and damage to the ground. These might occur on the

average of once per year at one location for each 100-mile section of line.

Diagnostic

This is maintenance work in the nature of an examination of the condition of the transmission system and is carried out on a planned schedule.

Examples of this type of maintenance are:

(i) Helicopter Patrols

Regular patrols of transmission lines carried out in accordance with the following schedule:

500 kV lines - 8 times each year
230 kV lines - 6 times each year
115 kV lines - 4 times each year

(ii) A walking physical inspection of the lines is carried out once a year.

Neither helicopter or walking patrols cause crop or ground damage and in general, this type of maintenance activity has a minimal effect on rights of way or property owners.

(b) Major Maintenance

These are planned repairs that could involve extensive work on a structure, such as footing repairs, or could cover several structures or miles of line, such as skywire replacement.

These repairs are usually planned as a result of conditions found during diagnostic maintenance.

They could be of several days duration and could cause crop damage or damage to the ground. The use of helicopters on such items as skywire replacement greatly reduces the amount of damage to property.

Major maintenance items are usually of such a nature as to permit long range planning and therefore can be scheduled to minimize the impact on rights of way and to property owners.

(c) Emergency Maintenance

Minor

These are repairs that must be carried out as quickly as possible and are usually restricted to one structure, such as the replacement of a string of broken insulators.

They are normally of one-half to one-day duration and could require the moving in of trucks with the resultant possibility of crop damage and damage to the ground.

Major

Major emergencies are usually the result of severe adverse weather conditions such as ice storms or tornadoes. They can affect several structures or miles of line.

In most cases it is necessary to restore the transmission line to service as quickly as possible and therefore heavy equipment and material must be brought into the area immediately.

These repairs can cause damage to crops and to the ground. However, the use of helicopters and special all-terrain vehicles can greatly assist in minimizing the damage.

In the planning and execution of all maintenance programs, a major consideration is to limit as much as possible the disruption to farm practices and to the environment.

The extended use of helicopters and the utilization of new and improved all-terrain vehicles in all maintenance practices greatly contributes to reducing the effect of maintenance requirements on rights of way and on property owners.

In cases where damage to farm practices or the environment has been unavoidable, the necessary restoration measures are carried out by Hydro, or the owner is compensated for the cost of such restoration, to return the right of way as nearly as possible to its original state.

B.3 Monitoring of Effects

The nature and magnitude of changes to the natural and social environment resulting from the construction, operation and maintenance of transmission facilities can vary widely depending upon the characteristics of the area being traversed. To obtain factual documentation about the effects in these diverse environmental settings, Ontario Hydro has instituted on new and existing rights of way an ongoing program of monitoring studies. The results of these studies will be used in developing and refining prediction procedures (the results of studies on farm productivity are already being applied in the environmental study methodology) and in establishing new or improved construction and long term management practices to reduce effects.

Monitoring studies are conducted in one of two ways; either through a systematic collection of data on new projects during construction and subsequent maintenance phases, or through special studies designed to answer specific questions. Typical of the former are a series of field trials being conducted in co-operation with the Ministry of Agriculture and Food to assess the effects of transmission lines on the productivity of various types of farming enterprises and also a three year investigation of the effects of soil compaction from heavy vehicles on crop yields. Other studies are documenting in the Beverly Swamp the effects of transmission facilities on a wetland environment. From these efforts is developed a picture of the actual changes which transmission facilities can reasonably be expected to create and an assessment of the effectiveness of mitigating techniques.

Ontario Hydro will be conducting such studies on an ongoing basis to improve its knowledge about transmission effects and because of the need to examine the environmental implications of changes in technology and practices. To anticipate requirements for such studies and to assist in assigning priorities among them, Ontario Hydro will maintain communication with the Ministry of the Environment and other affected ministries or agencies.

C. References

8A(1) ONTARIO HYDRO DOCUMENT "Protection of the Environment During Power Line Construction".

8A(2) ONTARIO HYDRO DOCUMENT "Specification for the Selective Cutting and Restoration of new 500, 230, 115 and 44 kV Transmission Line Right of Way".

APPENDIX 8-B

PROPERTY POLICIES AND PRACTICES OF ONTARIO HYDRO FOR HIGH VOLTAGE TRANSMISSION LINE RIGHTS-OF-WAY AND STATION SITES

CONTENTS

D. <u>Station Sites</u>

E. <u>Multiple or Joint Use of Rights-of-Way and Sites</u>

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Property Policies and Practices of Ontario Hydro for High Voltage Transmission Line Rights-of-Way and Station Sites

A. General Policy

More than 23,000 miles of transmission lines cross Ontario, carrying electricity from generating stations en route to consumers. Where these lines encroach on public or private properties, the necessary property rights are acquired by Ontario Hydro and the owners compensated.

In the past, Ontario Hydro specified the type of rights required for its transmission lines. Where possible, only easement rights were acquired but often outright purchase was necessary. In most cases, property settlements were obtained through negotiation. Expropriation was only resorted to when a settlement could not be reached before construction had to start in order that an adequate power supply could be provided to the area concerned.

On May 13, 1974, the Board of Directors of Ontario Hydro approved more flexible policies for the acquisition of transmission line rights-of-way. The policy was worked out in close cooperation with farm organizations and in consultation with several government Ministries and outside agencies.

In response to requests from the farm community, including the Ontario Federation of Agriculture, the National Farmers Union, and Christian Farmers Federation of Ontario, for full protection for farmers under The Expropriations Act, expropriation procedures are now applied to all owners. Although these procedures do not prevent negotiated settlements for compensation, they ensure that owners will have full protection of the Act, especially the Hearing of Inquiry, the Board of Negotiation, the Land Compensation Board and other rights guaranteed by the Act.

In most cases owners are given the choice of Ontario Hydro acquiring full ownership, or an easement in perpetuity of the land required for transmission line rights-of-way.

Where an easement is acquired, the owner may choose to be paid either in a lump sum or by an annual adjustable payment described below.

Where full title of the land is acquired for transmission rights-of-way, the former owner may in most cases license it back for agriculture at a nominal fee of $1 per acre per year, plus taxes. The licensing of Hydro owned lands has been responsible for maintaining approximately 16,200 acres of rights-of-way for food production.

As provided in The Expropriations Act, payment is based on the land's market value, together with compensation for damages and injurious affection where applicable, to which may be added

allowances for such matters as reasonable expenses and disturbance. As well, Hydro recognizes the special impact which a transmission line has on farm operations and is prepared to make an additional allowance for this disturbance.

Compensation for an easement over agricultural land is based on 75 per cent of the market value of the land to cover the basic right-of-way. To this is added an additional payment for tower structures. Details of the basis of calculation of compensation are set out in B.4 (a).

There is no corresponding easement compensation formula for non-agricultural land. In such cases the loss of value is determined by an appraisal.

These are, in brief, the policies which have been adopted in the acquisition program for transmission line routes. Most of the same policies apply in cases of acquisition of station sites. This subject is dealt with more particularly in D. below.

B. Acquisition Policies

B.1 Informing Affected Property Owners

When specific property requirements for new power facilities have been defined and government approval received, a meeting is arranged with affected owners to discuss the location of the right-of-way on their property. After this, the expropriation-negotiation process is started to acquire the needed property rights.

(a) Information Letters

A letter is sent to each affected property owner advising that acquisition procedures are being started. Local members of the Provincial Parliament and Mayors and Reeves are similarly advised.

(b) Public Meetings

The next step is to make owners fully aware of the property acquisition policies and procedures. For this purpose, a series of meetings are held in such places as local schools or community halls. The affected property owners are invited by letter. At these meetings, Hydro representatives explain the acquisition process in detail, including:

i) Expropriation procedures, their benefits and protections.

ii) The timing of events in the acquisition process.

iii) The options available to owners in granting the necessary property rights to Hydro.

iv) How compensation is determined.

v) How damages are corrected or compensated for.

vi) Forestry practices.

vii) Construction practices.

(c) Meetings with Individual Property Owners

Following the public meetings, a senior property agent and a right-of-way technician call on individual property owners. The technician discusses tower locations in an effort to minimize their impact on the property. Permission is requested to survey, appraise, do soil testing and, if necessary, do a woodlot evaluation. As required, further explanation and clarification of the acquisition policies is given. An "Information Package" containing the following material is left with the property owner:

i) A summary of the property policies and practices of Ontario Hydro for High Voltage Transmission Lines and Stations.

ii) A copy of the property acquisition schedule outlining predicted times of the various steps in the process.

iii) A copy of the pamphlet "Acquiring Land for High Voltage Transmission Lines". This pamphlet details acquisition policies and procedures.

iv) A copy of the booklet "Field Practices", setting out Ontario Hydro's standards of procedure and communication with land owners.

v) The location and telephone number of the property project field office where any inquiries or concerns can be directed.

B.2 Land Rights Required By Hydro

In acquiring property rights for transmission lines, the owner has generally the choice of allowing Ontario Hydro either to acquire an easement or full ownership of the land involved. There may be a few situations, such as in the immediate vicinity of stations, where engineering constraints require that Hydro own the land. But these are rare.

(a) Easement

An easement is a limited interest in the land and implies only a partial interference with the owner's rights to the land. In other words, by an easement Hydro buys certain rights and assumes certain responsibilities. The property owners sell certain rights and retain certain privileges.

When an easement is acquired, title to the property remains in the owner's name but becomes subject to the easement. The owner continues to be responsible for the property taxes. Although easements can take various forms, most are for the limited right of using a portion of the property for a power line route. The owner is not permitted to erect buildings on the easement. The easement includes the right to enter the property from time to time to inspect and do maintenance or repair and reconstruction work on the transmission line facilities. Where any damage occurs during the construction period or as a result of the required maintenance and repair, a Hydro representative will investigate and arrange for payment in settlement of the damage or arrange necessary repairs. This would include consequential and unavoidable damages to crops, tile drains, culverts, rutting, fences, and access roads.

(b) Full Title (Purchase)

When Hydro acquires full title to the land, it assumes ownership including responsibility for taxes and other aspects of land ownership. In virtually all cases of transmission rights-of-way across agricultural lands, the former owner can obtain a licence from Hydro to continue farming the land after the lines have been built. In accordance with the licence agreement, 12 months' notice is given prior to entry for construction and maintenance purposes. Where it is not possible to give the required notice, as in the case of an emergency, Hydro will compensate for the resulting loss or damage caused by the necessary work.

B.3 Property Appraisals

Compensation is based on the market value of the property, which is defined as the amount that the land might be expected to realize if sold on the open market by a willing seller to a willing buyer. The determination of market value, together with injurious affection where applicable, is made by a professional appraiser. The market value is usually determined from an examination of recent sales of similar properties in the same general area, with allowances made for time of sale, as well as factors such as location, improvements, zoning and soil quality. Injurious affection may occur where Hydro buys only part of a property. In such cases the effect on the remainder of the property that the owner continues to hold is

determined. If the value of the remainder is found to be reduced, due to size and shape, effect on buildings and such, then compensation for that reduction in value (injurious affection) is added to the market value of the purchased portion in making up the total compensation.

Ontario Hydro employs appraisers on its own staff but also uses independent appraisal firms to supplement this service. On major projects, Hydro will have all properties appraised by its own staff. Independent appraisers are retained to provide spot check appraisals as a comparison against the staff appraisals. The ultimate test of any appraisal occurs when it is presented in evidence before the Land Compensation Board. For this reason, appraisers closely follow the precedents set by this board as well as their own professional standards.

B.4 Compensation

The basis of compensation used by provincial government agencies in Ontario is spelled out in The Expropriations Act. The entitlements of owners have been clearly set forth. No owner should be put in a position of financial loss as a result of action taken by any expropriating authority.

(a) Easement

In the case of agricultural lands, the compensation formula recognizes the market value of the land, plus the impact of the transmission line on the farming operation. Under the formula, compensation for an easement is based on 75 per cent of the market value of the land to cover the basic right-of-way. To this is added an additional payment for any tower structures which will be required: compensation for the first structure is based on 75 per cent of the market value of one acre of land. This compensation is increased by 5 per cent for each additional structure. For example, compensation for the second structure is 80 per cent of the value of one acre of land, 85 per cent for the third structure and so on. Minimum payment for one structure is $100.

An owner can choose to receive an annual payment for the easement instead of a lump sum. The annual amount is determined by applying the chartered bank prime interest rate plus 1/2 of 1 per cent to the equivalent of the lump sum payment. For example, if the current chartered bank prime rate is 9 1/2 per cent, then the current annual payment will be 10 per cent of the lump sum value of the easement.

The annual payment will be re-assessed periodically as follows: the interest rate to be used will be established on January 1 of each year after the initial payment. The value of the easement, based on the market value of the land, will be reviewed every five years. Thus, the annual

payment will continue to be related to current land values and interest rates.

(b) Full Title (Purchase)

Sometimes both owner and Hydro agree that it is appropriate for Hydro to buy an entire property. This could apply, for example, where an owner's residence or main buildings are involved. It may also be appropriate in cases where most of the property is required and the remainder is too small to permit the owner to continue effectively in his normal operations, even with a licence to use the right-of-way. In such cases, Hydro would offer to sell the surplus property to the local municipal utility, municipality or Ontario Government agencies, sell it on the open market, or arrange an exchange with other affected owners.

If it is necessary to buy an entire property, requiring an owner to move his residence, allowances will be included in the offer based on estimates obtained covering reasonable moving and relocation costs.

The Act also makes provision for payment of other allowances such as disturbance, legal and survey costs, as applicable. In addition, Hydro recognizes the special impact which a transmission line has on a farm operation and is prepared to make an allowance for this disturbance. The allowance is related to market value of the required land.

B.5 Compensation Information

After the appraisals have been made, a separate staff of property agents call upon property owners to inform them of the compensation they may expect under the various options available to them. At this stage, Ontario Hydro is not negotiating for rights, but only informing owners of the amount they may expect to receive. This additional information is useful to owners in making a decision whether or not to request a Hearing of Inquiry. It also gives them more time to consider the offer.

C. Expropriation Procedure

C.1 Application for Approval to Expropriate

As a first step in the expropriation process, Ontario Hydro must make application to the approving authority, the Minister of Energy, for approval to expropriate land rights. The application essentially consists of a list of the properties affected and, in the case of a limited interest (easement) expropriation, a description of the rights required.

C.2 Notice of Application

Following application to the approving authority, each affected owner will personally receive a "Notice of Application for Approval to Expropriate Land". The "owners" of land, as defined in The Expropriations Act, include tenants, mortgage-holders, creditors with property liens and others with a legal interest in the property.

This notice sets out the specific property rights to be expropriated. It also tells owners how to request an inquiry into the proposed expropriation, if they wish.

To ensure that everyone with an interest in the affected properties is aware of the proposal, a copy of the notice is published in a local newspaper once a week for three consecutive weeks.

An owner who objects to the proposed expropriation may write to the approving authority designated in the notice, requesting an inquiry. The request must be filed within 30 days of receiving the notice.

C.3 Inquiry Hearings

A prime example of how the Expropriations Act is designed to protect the interests of both the individual owner and the expropriating authority is the Inquiry Hearing (sometimes referred to as the Hearing of Necessity).

Essentially, the Act provides for: a hearing at which the individual property owner may make his views known to an Inquiry Officer appointed at the request of the Minister of Energy, to establish whether the acquisition is fair, sound and reasonably necessary.

The Inquiry Officer reports to the Minister with a summary of the evidence, his findings and opinion on the merits of the application. Negotiations will not start until after the Inquiry Hearing.

C.4 Minister's Decision

After considering the report of the Inquiry Officer the Minister will either approve, approve with such modifications as he considers proper, or not approve the proposed expropriation.

C.5 Expropriation

Shortly after approval and while negotiations are continuing, Hydro will register a plan in the local registry or land title

office which has the effect of transferring the property rights to Ontario Hydro.

Notice of the expropriation, together with a Notice of Election and a Notice of Possession will then be delivered to each owner. The Notice of Election gives the owner his choice of one of three dates he wants used in evaluating his compensation: the date he received his Notice of an Inquiry, the date the expropriation plan was registered, or the date he received this Notice of Expropriation. The Notice of Possession specifies the date on which Hydro requires access to the land concerned.

C.6 Offer of Compensation

If no agreement over price can be reached after a property has been expropriated, Ontario Hydro will offer each owner Hydro's estimate of full compensation for his interest in the land expropriated, and - except where the "owner" is a tenant - a statement of the total compensation being offered for all interests (such as mortgages) in the land. In addition, each owner will be offered immediate payment of 100 per cent of the market value of his interest in the land as estimated by Ontario Hydro, without prejudicing his right to have compensation determined by subsequent negotiations or by the Land Compensation Board.

C.7 Arbitrating Compensation

The Province of Ontario has established a Board of Negotiation consisting of two or more members appointed by the Lieutenant Governor. Hydro or the owner can request the assistance of the Board of Negotiation, which will conduct a hearing, visit the property, and make a recommendation of what it considers adequate compensation. However, its recommendations are not binding.

If either party does not accept the Board's recommendation, the Land Compensation Board - also a government tribunal may be requested - to determine the amount of compensation. This amount, set by the board, if not appealed within 30 days, does become binding on both parties.

D. Station Sites

To this point the property policies and practices have been dealt with in terms of transmission line rights-of-way. The same policies and practices are applicable to transformer and generating station sites except that owners are not given the choice of Ontario Hydro acquiring full ownership or an easement in perpetuity. Ownership of the land in such cases is essential to meet the necessary standards of safety and security.

E. Multiple or Joint Use of Rights-of-Way and Sites

E.1 Urban Areas

Possible public uses of existing transmission line rights-of-way are constantly being investigated. In fact, many rights-of-way are being used for various purposes such as garden plots, golf courses, bicycle paths, walkways, subway access, parking material, storage, pipelines and railways.

Ontario Hydro cooperates with municipalities and government agencies in permitting rights-of-way and station site lands to be used for other purposes, such as parks, where feasible. For example, part of the area surrounding the Pickering generating station site is currently used by the Metropolitan Toronto and Region Conservation Authority and the Town of Pickering for recreation purposes. In such cases, Ontario Hydro makes a minimal charge for use of these lands and the municipality or park authority assumes the responsibility for normal maintenance. In the cases of commercial uses (such as car parking and material storage), Ontario Hydro cooperates with owners of adjoining land in enabling them to use its rights-of-way at prevailing local rental rates.

E.2 Agricultural Areas

The most common use of transmission line rights-of-way in rural areas is for agriculture, as in most cases former owners or owners of adjacent land want to retain or incorporate these lands in their existing farm operations. Nominal rents are charged for right-of-way lands as an inducement to keep them under cultivation. This keeps the acreage productive as well as lessening the impact on the area by the lines themselves. Constant liaison with the Ontario Federation of Agriculture, the National Farmers Union, Christian Farmers Federation of Ontario, and other farm groups helps promote the use of rights-of-way.

E.3 Other Uses

Where headponds were required in the past for the development of hydro-electric stations on major rivers, the necessary lands were acquired by purchase or expropriation, and residences and farm buildings were removed or relocated to higher ground.

Where feasible these areas are used for public recreation and in many cases, property owners have built cottages and homes beside these headponds.

E.4 Conclusion

In general, Ontario Hydro makes every attempt to be a responsible property owner and a good neighbour. Ontario Hydro

is by legislation exempt from Municipal taxation. However, grants equal to full taxation are paid on all owned property. Hydro and its tenants also maintain the leased lands. Efforts are made to have Hydro property used in a manner conforming and fitting into the environment of the locality, and Hydro consults and cooperates with the Municipalities to this end.

Appendix 8-C

Electrical Effect on the Environment (Humans, Animals, Vegetation)

The operation of transmission lines produces electric and magnetic fields in the space around the lines. The effect of the electric field is to induce voltages and/or currents on objects in the space near the line. The magnetic field induces voltages and currents in metallic objects near the line. Under certain conditions, corona is generated. Corona can produce audio, radio and television noise near the line and traces of ozone adjacent to the conductor.

Some of the effects must be controlled to ensure safe and reliable operation of the lines. Others must be regulated to reduce to acceptable levels interference with other public services and other users of the lands beneath and adjacent to the lines. The magnitude of each of the effects depends on the line voltage and/or current, line height, conductor spacing and design, and the construction practices followed. The effects are discussed below.

(a) Corona

Corona (Ref 8C(1,2)) can occur on conductors and line components when the electric field intensity or voltage gradient at the conductor surface exceeds the insulation strength of air immediately around the conductors.

The research conducted in the 1950's by Ontario Hydro established the criteria for the design of EHV transmission lines to be virtually free of corona under fair weather conditions. This is accomplished by controlling the conductor size, bundle arrangement and phase spacing. To ensure that the benefit of the above factors is not reduced, corona free conductor hardware was designed and a guide for handling and stringing of conductors was developed.

By controlling corona levels, the audio, radio and television noise and ozone effects are reduced.

In foul weather, corona activity increases due to electric field distortions caused by water drops on the conductor surface.

(b) Ozone

Ozone is a naturally occuring gas related to oxygen and having a characteristic odour.

High voltage transmission lines make no significant addition to the amount of ozone present in the

atmosphere at ground level under any weather conditions (Ref 8C(1, 3, 4, 5)).

(c) Radio Interference (RI)

Radio noise (Ref 8C(1, 6, 7, 8)) is generated by corona on various line components and by minute discharges at small air gaps that may exist with loose hardware. Figures 1 to 3 of this appendix show the calculated Radio Noise profiles for some of the rights of way shown in Figures 8-8 to 8-11 of the Main Report. The radio noise values are expressed in dB above 1 uV/m, as measured by a meter conforming to CSA Standard C108.1.2. Figure 4 is included to show the calculated radio noise profile for earlier Ontario Hydro 230 kV two circuit lines. The favourable experience with these lines and with thousands of miles of line operating all over the world at voltages up to 765 kV is the best assurance that radio reception will be satisfactory. Only in exceptional cases has reception been impaired and most of these problems have been successfully resolved.

National standards (Canadian Electrical Code, Part III, CSA Standard C108.3.1) protect local signals in the AM radio band in fair weather. The prescribed values of tolerable noise levels are 50, 57 and 60 dB for 230 kV, 500 kV and 765 kV lines respectively, measured at a point 50 feet laterally from the outermost conductor at ground level. Ontario Hydro's criterion is to limit the maximum fair weather level at a point 10 feet outside the right of way to 40 dB, which at least equals the national standard in all cases.

In foul weather, interference levels will increase due to increased corona. These levels will produce some interference with the weaker local AM signals. Due to the inherent noise-rejection properties of FM receivers, there should be no detectable interference with any reasonable FM signal in fair or foul weather.

(d) Television Interference (TVI)

The minute electrical arcing generated from loose conductor support assemblies or other hardware can also produce interference at very high frequencies (within FM and TV frequency bands). It is not difficult to detect and can be readily corrected.

Precipitation-type television interference (Ref 8C(1, 7, 9, 10)) occurs where there is light drizzle, heavy rain, dry snow or wet snow on the conductors. These are known as foul weather conditions. Efforts have

been made to correlate foul weather television interference with foul weather radio interference. A study conducted for 500 kV lines has shown that foul weather TVI levels are less than 2 percent of the foul weather RI levels.

The IEEE Subcommittee on Radio Noise concluded that there is no confirmed data that TVI is caused by corona from overhead power lines during fair weather conditions (Ref 8C(7)).

Shielding and "ghost" effects caused by transmission lines have been rare and minimal. One reason may be that they are masked by the much larger effects produced by large buildings. Tests have shown that some effects may be noticed close to very tall transmission line structures in open country. In such cases, re-orientation of the receiving antenna will usually provide a remedy.

(e) Audible Noise

EHV transmission lines can create audible noise (Ref 8C(1, 11, 12, 13)) to some extent. It occurs mainly during heavy precipitation when corona generation is at its maximum.

It can be limited by designing the lines to reduce the electric field intensity at the surface of the power conductors; for example, by using larger conductors. Figures 5 to 7 show the calculated audible noise profiles across the rights of way for foul weather conditions for some typical cases.

In the USA, some complaints have occurred involving EHV lines operating at higher conductor surface voltage stresses than Ontario Hydro's design practice permits. The USA experience has shown that some complaints are received with audible noise levels between 52.5 and 58.5 dBA and numerous complaints occur when the audible level exceeds 59 dBA. By comparison, average traffic on a street corner produces a noise level of 70 to 80 dBA and conversational speech about 60 to 70 dBA. A typical business office has a sound level of about 50 to 60 dBA.

Maximum calculated noise levels for Ontario Hydro 500 kV lines, during heavy rains, are approximately 55 dBA at the edges of the rights of way.

(f) Electromagnetic Induction

Current flowing in the conductors of power lines causes an electromagnetically induced voltage to appear in parallel conductors (Ref 8C(1, 14, 15, 16,

25)). These conductors may be other transmission lines, communication circuits, fences, pipe lines, or other metallic objects, either above ground or below, insulated or uninsulated.

The induced voltage appearing at the open ends of partially grounded parallel conductors can be in the order of 0.1 volts per mile per ampere of line current (Ref 8C(14)). The effect is independent of the line voltage, but increases with line current and the length of the parallel and decreases as the parallel conductors are separated.

Properly developed design, construction and operating practices will eliminate any hazardous electromagnetic induction effects.

(g) Electrostatic Induction

Energized conductors are surrounded by an electric field, sometimes referred to as an electrostatic field (Ref 8C(1, 17-26 incl.)). The magnitude of the electrostatic field under transmission lines depends on the voltage level of the conductor and the distance from the conductor to the ground. Figures 8 and 9 show the profile of the calculated electric fields across the right of way at ground level for some of the proposed line arrangements being considered for multiple line rights of way. Two conditions are shown in each figure. One depicts the electric field strengths (expressed as voltage gradient at ground level) for lines carrying their normal maximum loads. The second shows the ground gradients with one circuit out of service, and the other circuit carrying the maximum emergency load. These emergency conditions would be very infrequent and of short duration.

The electric field strengths under Ontario Hydro lines, even under these emergency conditions, are less than the field strengths that would exist under lines at the minimum clearances specified in the Canadian Electrical Code, CSA Standard C22.3 No. 1.

(h) Biological Effects of High Voltage Electric Fields

During the past ten years there has been growing concern about the possible biological effects of electric fields induced by very high voltage power lines and substations. Although Ontario Hydro is convinced that there have been no health effects on workers exposed regularly to high intensity electric fields, Ontario Hydro keeps well informed on research and literature on this subject. The most significant issue is whether long term

exposure to electric and magnetic fields can have deleterious effects on human, animal and plant life.

Research to date in Western Europe and America has failed to provide any significant evidence of harmful biological effects. On the other hand, studies performed in the USSR report some undesirable effects on workers in high voltage substations. Many of these effects were subjective or clinically not significant. Laboratory studies on small animals done in the USA in simulated electric field environment have been somewhat contradictory or inconclusive.

(i) USSR Studies (Ref 8C(27, 28, 29, 30, 37))

Workers occupationally exposed to high voltage electric fields in the complex environment of switchyards complained of disorders such as headache, tiredness, lassitude, excessive sweating, irritability and loss of sexual libido. Clinical patterns described were mainly subjective with little or no evidence of clinically significant disease. Coronary artery disease found in three men over 50 years of age would not be unusual in any group of 45 males. Most of the blood changes described appear to be of little clinical significance.

In a second paper, increases in blood pressure and pulse with exposure to 500 kV appear to be quite within normal limits. It is difficult to interpret the significance of the Soviet findings. Most physicians who have studies their research carefully agree that the psychological symptoms are probably related to unhappiness with the job, the location of the station or the high noise in the switchyards. Most of the physical findings would be common to any similar group of workers unexposed to electric fields.

It is significant to note that the permissible field intensities under transmission lines in the USSR are considerably higher than those under lines in Canada (Ref 8C-37).

(ii) "Power over People" by Louise B. Young (Ref 8C(31))

This book has been widely read and publicized in the media. Mrs. Young's original concern was with the aesthetics of transmission lines and towers. Subsequently she condemned utilities for building transmission lines, citing high corona discharges with the alleged production of

ozone that this implies. She quoted the Russian research but produced little evidence to substantiate biological effects. Subsequent studies have proven that insufficient ozone is produced to affect health or vegetation.

(iii) Review of Literature and Research by Dr. Andrew A. Marino (Ref 8C(32))

Dr. Marino is a biophysicist whose primary interest has been the effect of electric current on bone. Most of his experimentation has been done on rats. He has also reviewed extensively the literature regarding biological effects of electric fields on laboratory animals.

His main conclusion is that electrical fields have a biological effect on living organisms. From his own experiments on rats he concludes that electric fields produce a specific stress reaction. He has done no studies on humans who have been exposed to the electric fields of switchyards or transmission lines. In spite of this, he has recommended that 765-kV lines should not be built.

(iv) Research by Dr. Robert O. Becker (Ref 8C(33))

Dr. Becker is an orthopedic surgeon who has worked with Dr. Marino. His research is highly theoretical, bearing little resemblance to actual field transmission line conditions. He makes the assumption that what applies to experimental animals in the laboratory, applies equally to humans in proximity to high voltage conductors. As in the case of his colleague, there is no evidence that he has done any practical measurement of electric currents under field conditions.

(v) Johns Hopkins University Study 1972 by Drs. M.L. Singewald, O.R. Langworthy and W.B. Kouwenhouven (Ref 8C(34))

This study was done on ten linemen working on 765-kV and 345-kV lines over a period of about nine years. They were in excellent health and between the ages of 30 to 47 years at the beginning of the study. Some worked bare handed and others used live line tools. The bare-handed workers were protected by conductive clothing and gloves.

Each lineman received seven complete physical and psychological examinations together with extensive laboratory tests, including

electrocardiogram and eletroencephalogram. X-rays of the chest and hands were done at each examination. Sperm counts were done by a urologist at each examination and were found to be normal.

These very thorough examinations revealed no significant changes of any kind with all the men remaining healthy. No change which could possibly be related to electric field exposure was found throughout the study. The psychiatric assessment of emotional status was directly opposite to the observations of the Russians (Ref 8C(27)).

(vi) Biological Measurements in Rodents Exposed Continuously Through their Adult Life to Pulsed Electromagnetic Radiation
- by S.J. Baum, M.E. Ekstrom, W.D. Skidmore, D.E. Wyant and J.L. Atkinson (Ref 8C(35))

Rodents were exposed continuously for 94 weeks of their adult life to very strong electromagnetic fields. Thorough blood and bone marrow studies, relating to effects on fertility and reproductive capability, were done. The rats were also examined for the development of tumors and other adverse health effects.

At no time did any of the biological measurements in over 300 irradiated male rats and 40 female rats show any ill effects of the electromagnetic pulse radiation. In this study 300 control rats were also examined. The female rats which were exposed throughout their gestation period gave birth to normal progeny both from a first and second pregnancy.

The conclusions of this research are in sharp contrast to those of Drs. Marino and Becker.

(vii) Study by Pierre F. Roberge, M.D. - Hydro Quebec (Ref 8C(36)

This study on 57 electrical workers was done in the latter half of 1975. All men had worked for Hydro Quebec for a minimum of 2 years as maintenance electricians on 765-kV substations.

The paper has not yet been published but Ontario Hydro has been provided with a summary. Publication is awaiting completion of laboratory studies.

The clinical and psychological studies failed to show any significant health effects which could

be ascribed to exposure to high voltage electric fields. Dr. Roberge mentions specifically that the results did not show the syndromes reported by the Russians.

(viii) Ontario Hydro Experience and Planned Research

In Ontario Hydro about one hundred linemen work regularly bare hand or with live line tools on 230 and 500-kV lines. In addition, many others work in high voltage substations and on lines of lower voltage. While no definitive medical studies have been done on these men, many have been seen medically for other reasons. They have lived normal lives, have normal families and have shown no signs of poor health or disease which can be attributed to electromagnetic or electrostatic fields.

On the basis of the above and other extensive study of research and literature, Ontario Hydro believes there are no significant deleterious effects on human health from high voltage alternating current electric fields. However, with the present state of knowledge it is imperative to keep an open mind. Therefore, Ontario Hydro plans an independent study of about 30 linemen and electrical workers who have been exposed to high voltage fields for at least five years. An equal or larger number of controls would also be examined. An approach has been made to the Canadian Electrical Association to sponsor such a study.

To avoid any suggestion of bias, the study will be done by outside specialists and co-ordinated by the University of Toronto. A thorough examination, similar to that done in the Johns Hopkins study, is planned but its exact nature and scope will be decided by the research group of the University of Toronto.

Ontario Hydro hopes that by keeping well informed on world-wide research and published reports and by doing its own study, concern about exposure to high voltage electric fields will be dispelled.

(i) Fences, Building, Irrigation Pipes

As discussed in (f) and (g) above, electrostatic and electromagnetic voltages and currents are induced in metallic objects located in the electric and magnetic fields generated by transmission lines (Ref 8C(14, 17-20 incl.)). These metallic objects can be fences, irrigation pipes, antennas, roofs and walls of buildings, eavestroughs and downspouts. To eliminate any possible hazards from induced voltages and currents, metallic objects close to the line are grounded.

Most fences are adequately grounded because of their type of construction. Those that are not, are grounded at intervals frequent enough to keep electromagnetically induced voltages and circulating currents to acceptable levels. They are also grounded at gates and at random breaks in the fences. Electric fences are grounded through filters. Irrigation systems, which do not have a metallic contact with ground, should be adequately grounded.

All large metallic buildings or structures, which are close to the right of way and insulated from ground, are grounded if necessary. No buildings are allowed directly under transmission lines.

(j) Lightning and Fault Currents

All high voltage towers are grounded. Overhead ground cables are used to carry fault and lightning stroke currents to ground. They are positioned to intercept lightning strokes and thereby shield the power conductor. They also provide some shielding to the ground below. If lightning should strike a line, the lightning current will seek the shortest path through the tower to ground. This current will produce a rise in voltage on the tower and in the adjacent ground due to the resistance of the ground to the flow of current. Similar voltages exist near trees and man-made structures during a lightning storm. Because trees and other man-made structures are usually not as well grounded as a tower, voltages encountered near trees and other structures are generally higher than near a tower. These transient voltages disappear in a matter of microseconds. Under line fault conditions, a current flowing to ground through a tower will produce similar but lower voltage rises.

The voltages that a person in the vicinity of such an affected structure could be exposed to are commonly referred to as step and touch potentials. High voltage transmission lines are designed to reduce the possibility of flashover. Protective relaying is

provided which will open circuit breakers and de-energize the line within 0.1 of a second.

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TYPICAL RADIO NOISE PROFILES
FOR 2, 1-CCT 500kV LINES
TYPE Z11S TOWERS

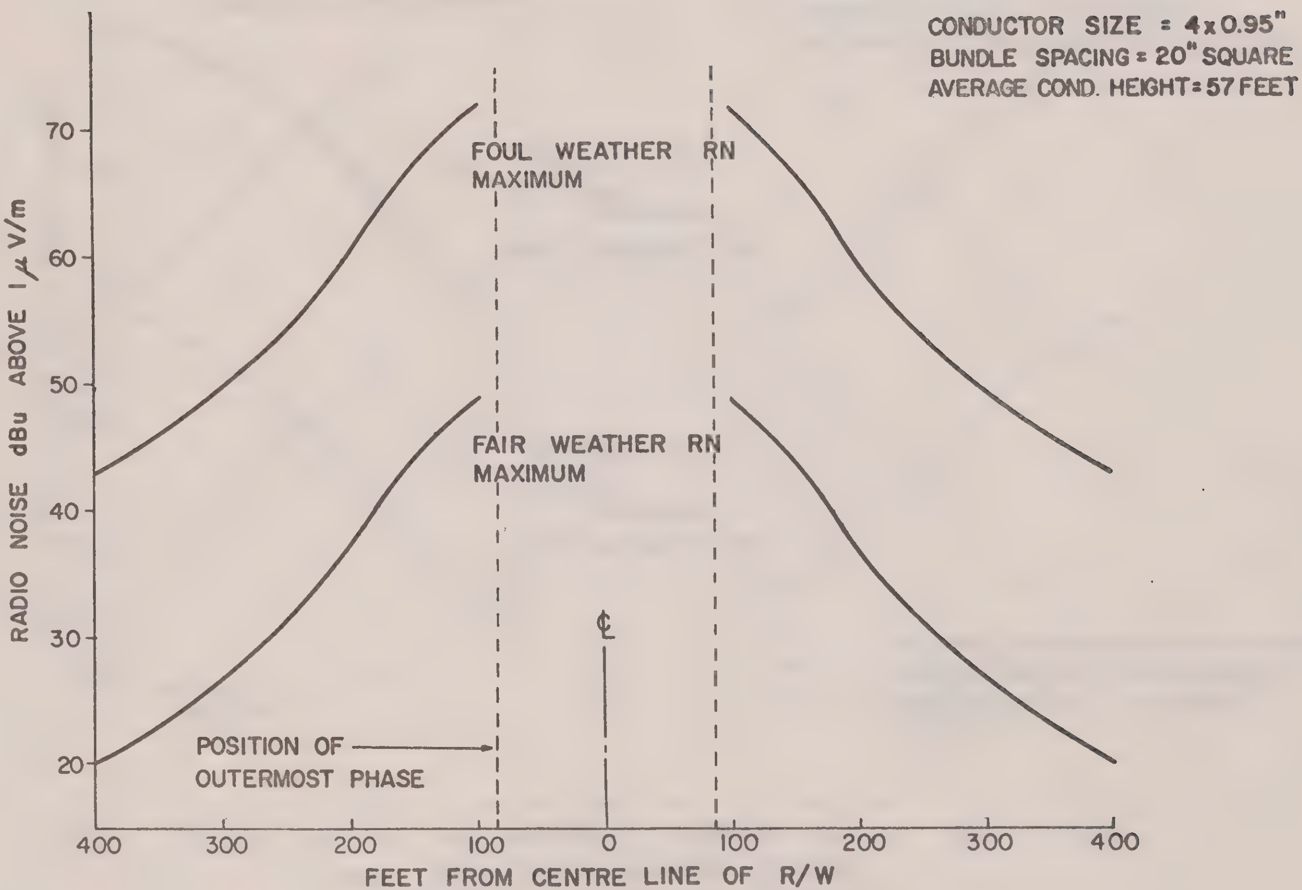

FIGURE I

TYPICAL RADIO NOISE PROFILES
FOR 2, 2-CCT 500kV LINES
TYPE V1 TOWERS

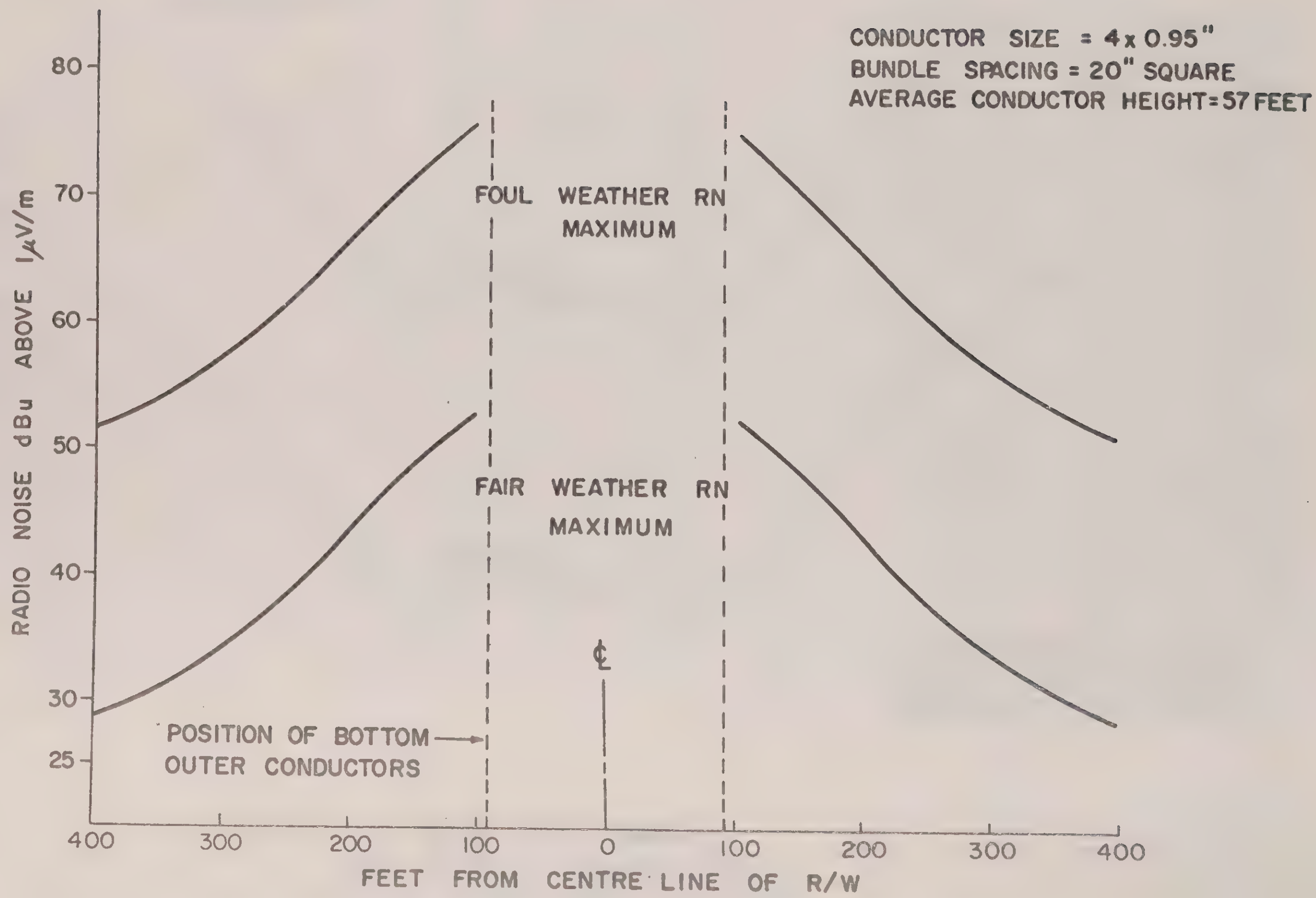

FIGURE 2

TYPICAL RADIO NOISE PROFILES
FOR 2, 1-CCT 765 kV LINES
HYDRO QUEBEC RIGID TOWERS

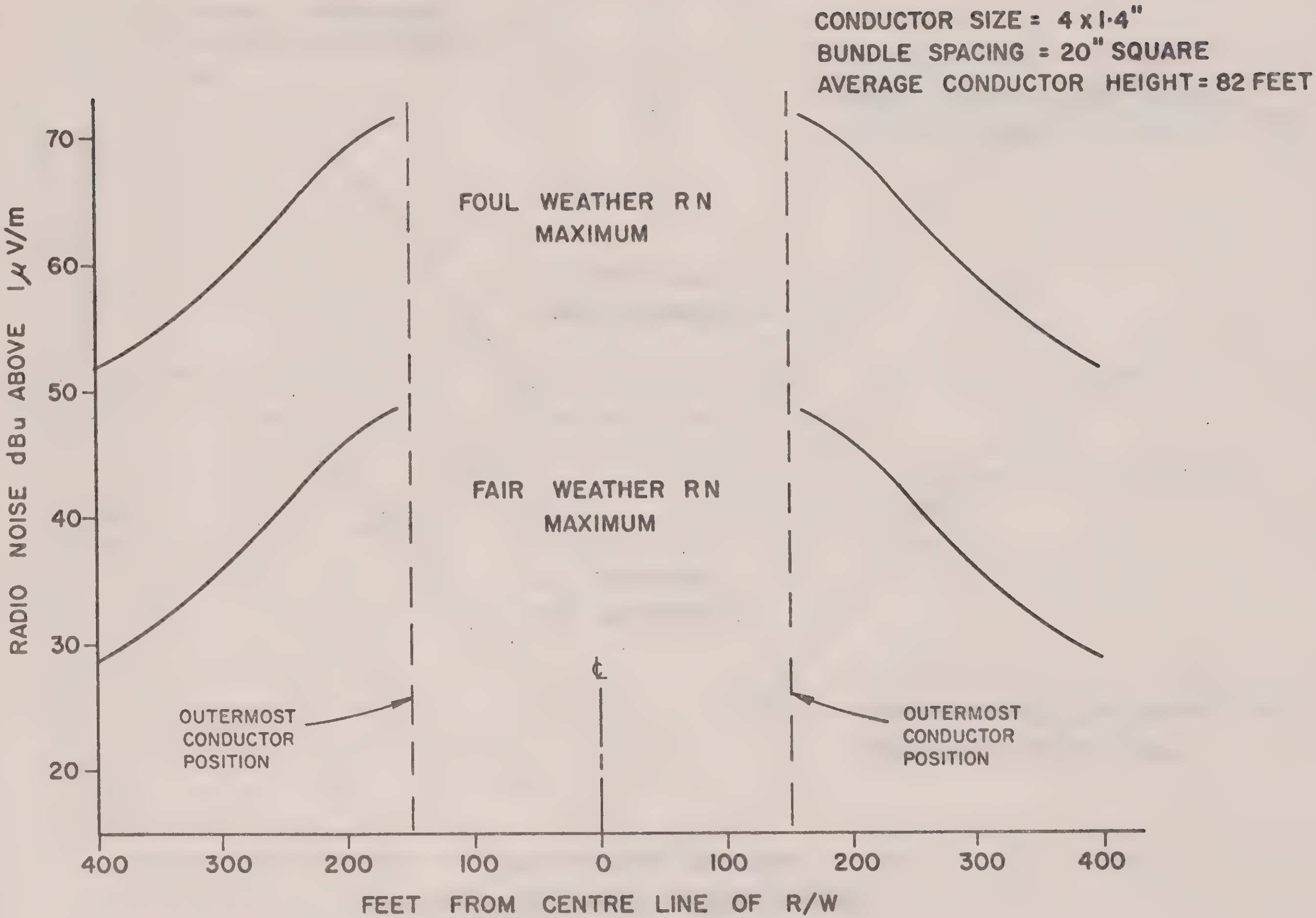

FIGURE 3

TYPICAL RADIO NOISE PROFILES
FOR 2, 2-CCT 230kV LINES
1948 TYPE TOWERS

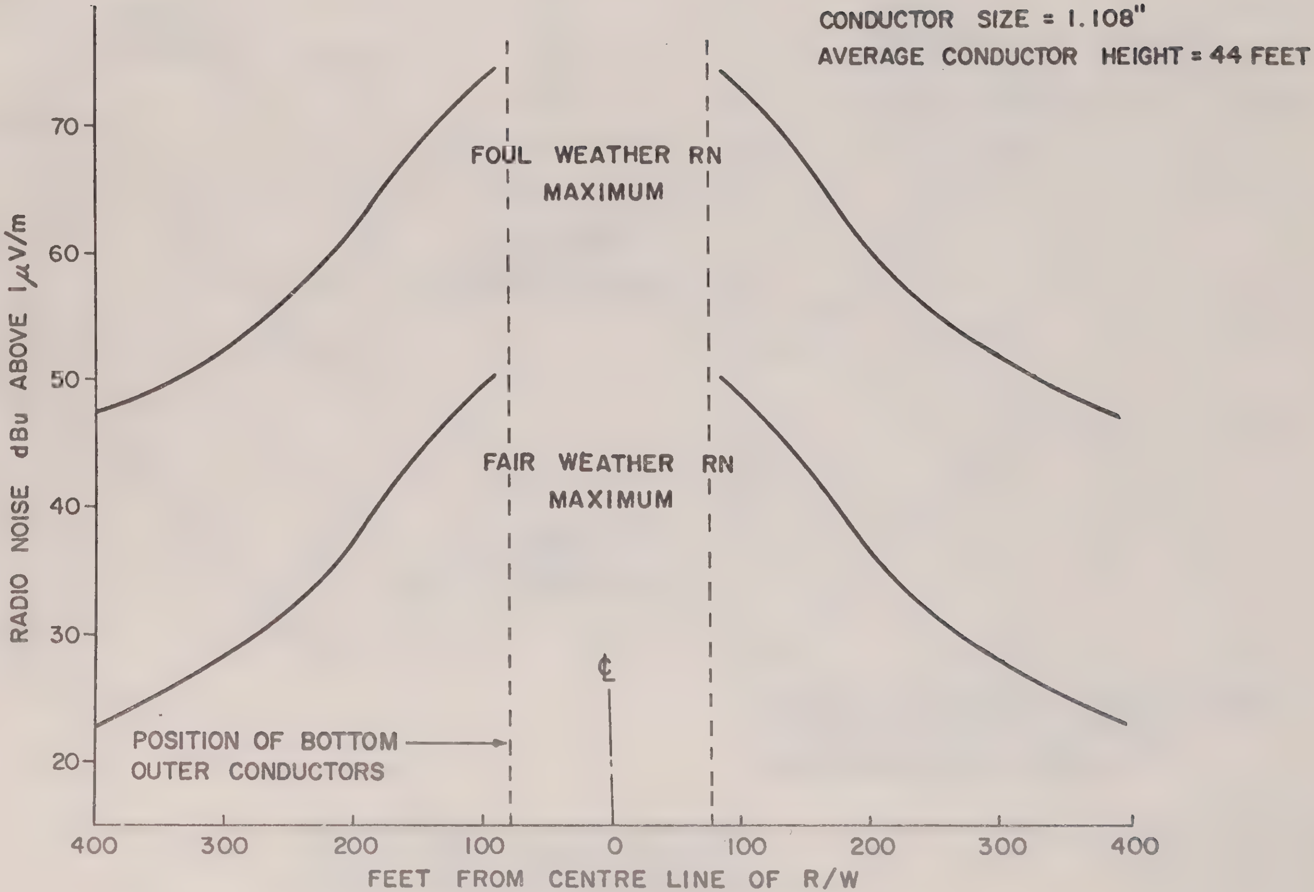

FIGURE 4

TYPICAL AUDIBLE NOISE PROFILES
FOR 2, 1-CCT 500kV LINES
TYPE Z11 TOWERS

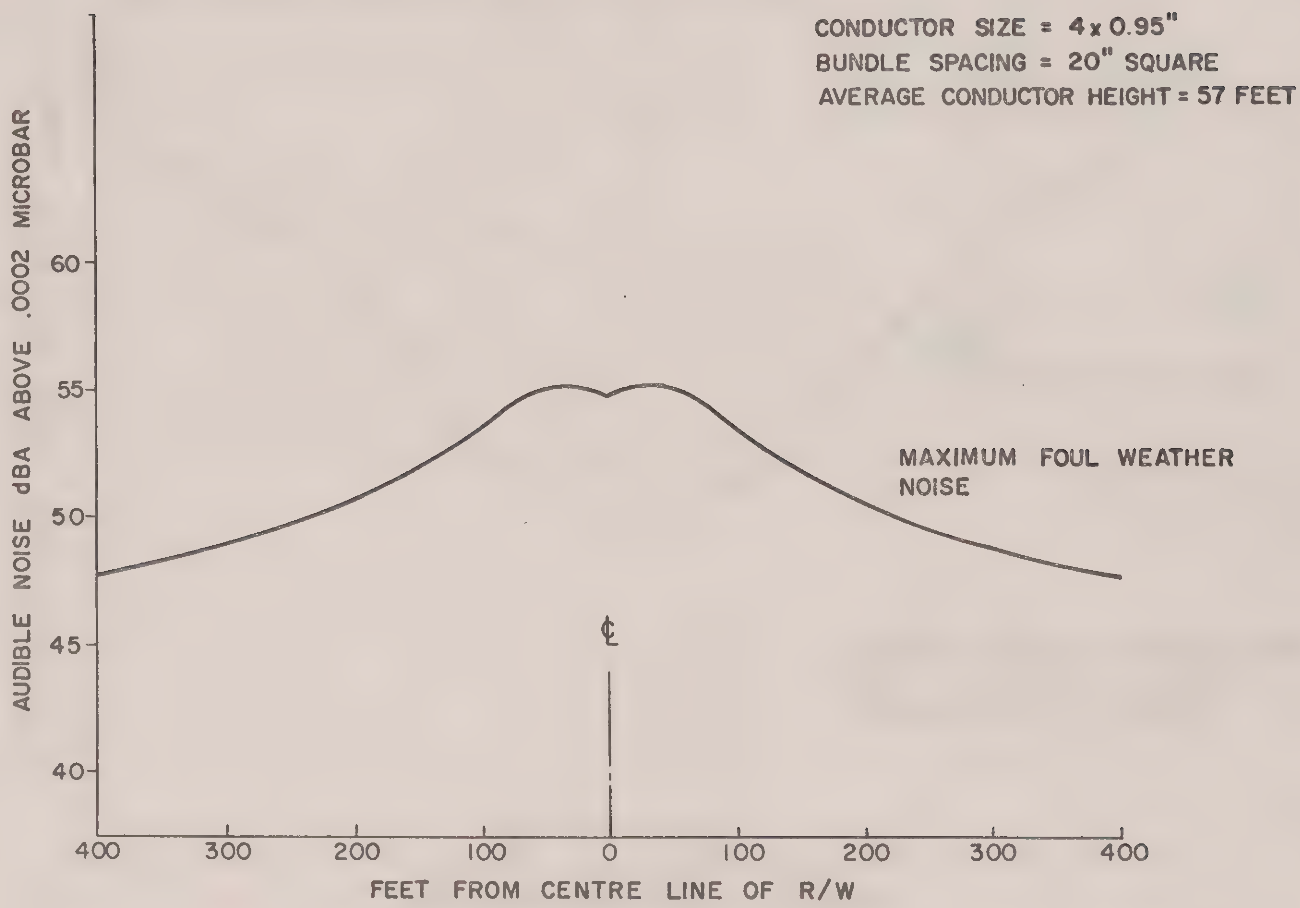

FIGURE 5

TYPICAL AUDIBLE NOISE PROFILES
FOR 2, 2-CCT 500kV LINES
TYPE V1 TOWERS

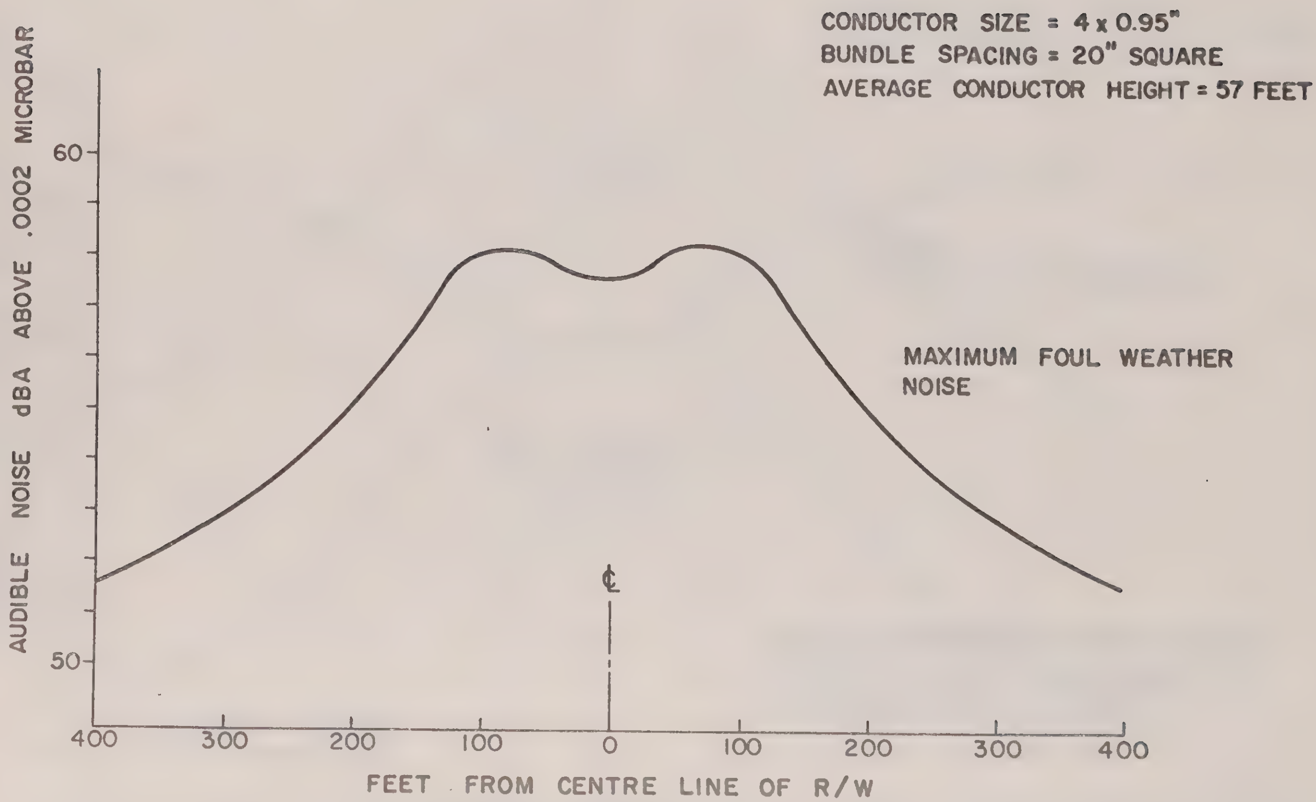

FIGURE 6

TYPICAL AUDIBLE NOISE PROFILES
FOR 2, 1-CCT 765kV LINES
HYDRO QUEBEC RIGID TOWERS

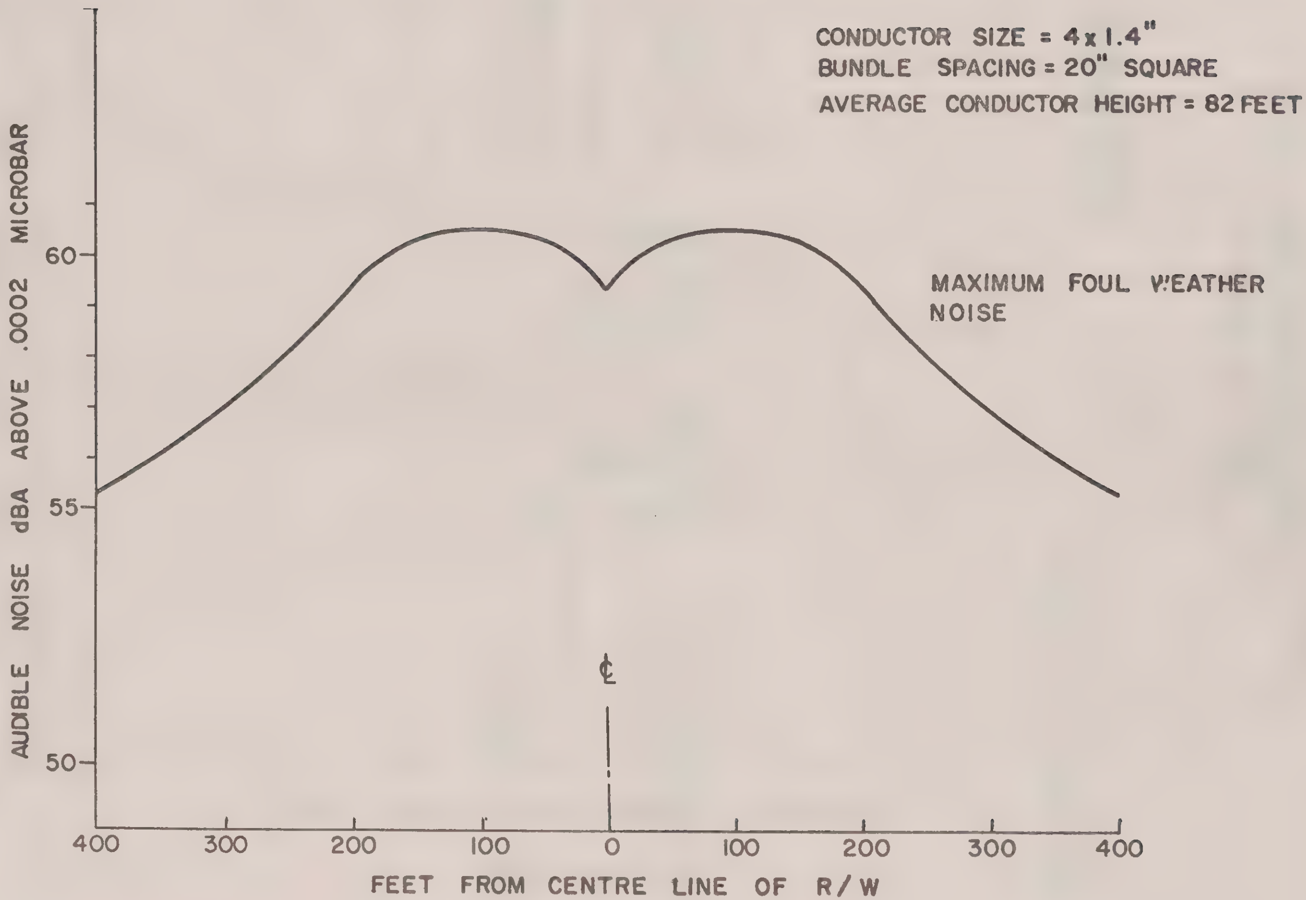

FIGURE 7

GROUND LEVEL VOLTAGE GRADIENT PROFILES
FOR 2, 1-CCT 500kV LINES
TYPE Z11 TOWERS

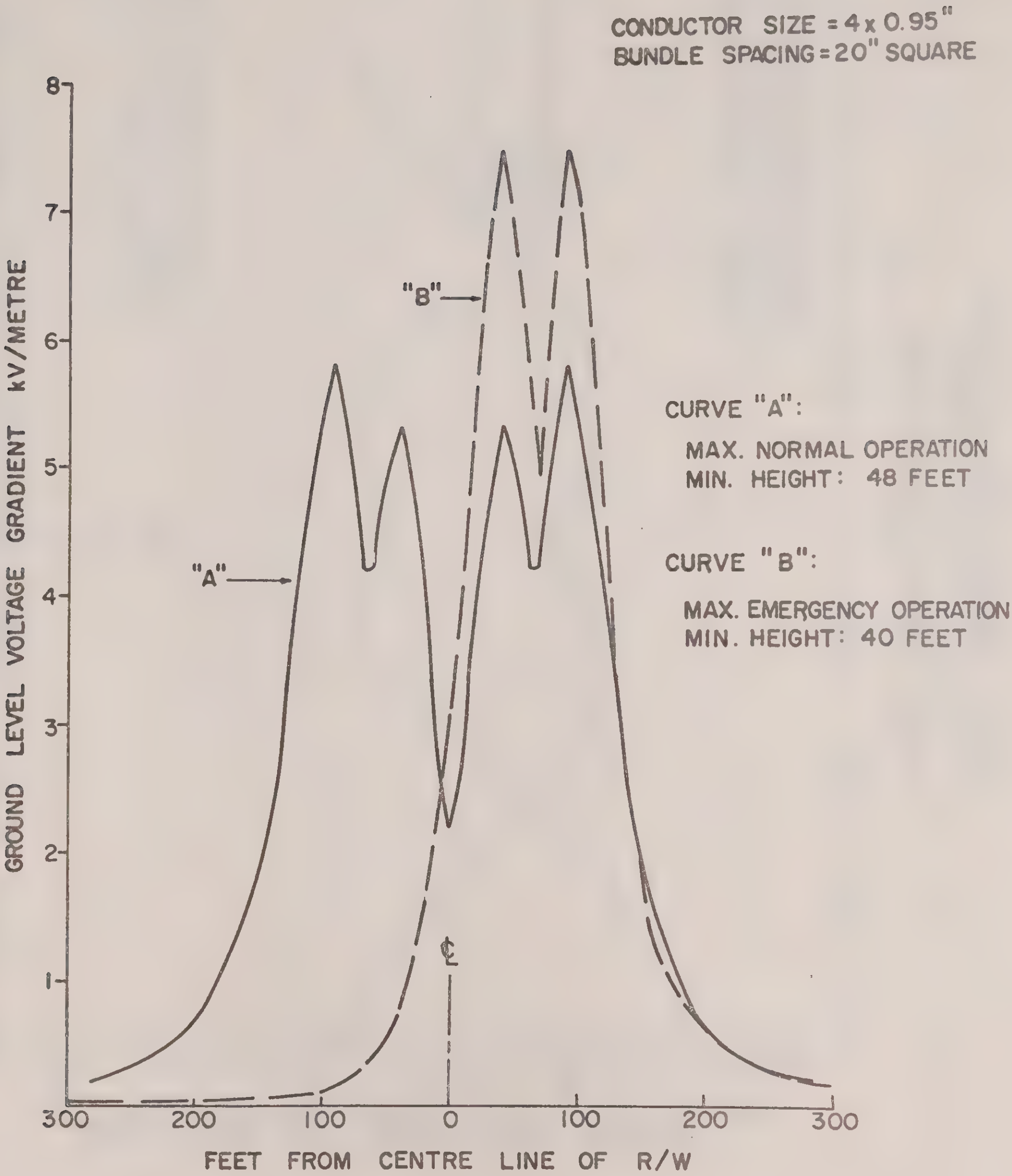

FIGURE 8

GROUND LEVEL VOLTAGE GRADIENT PROFILES
FOR 2, 2-CCT 500kV LINES
TYPE V1 TOWERS

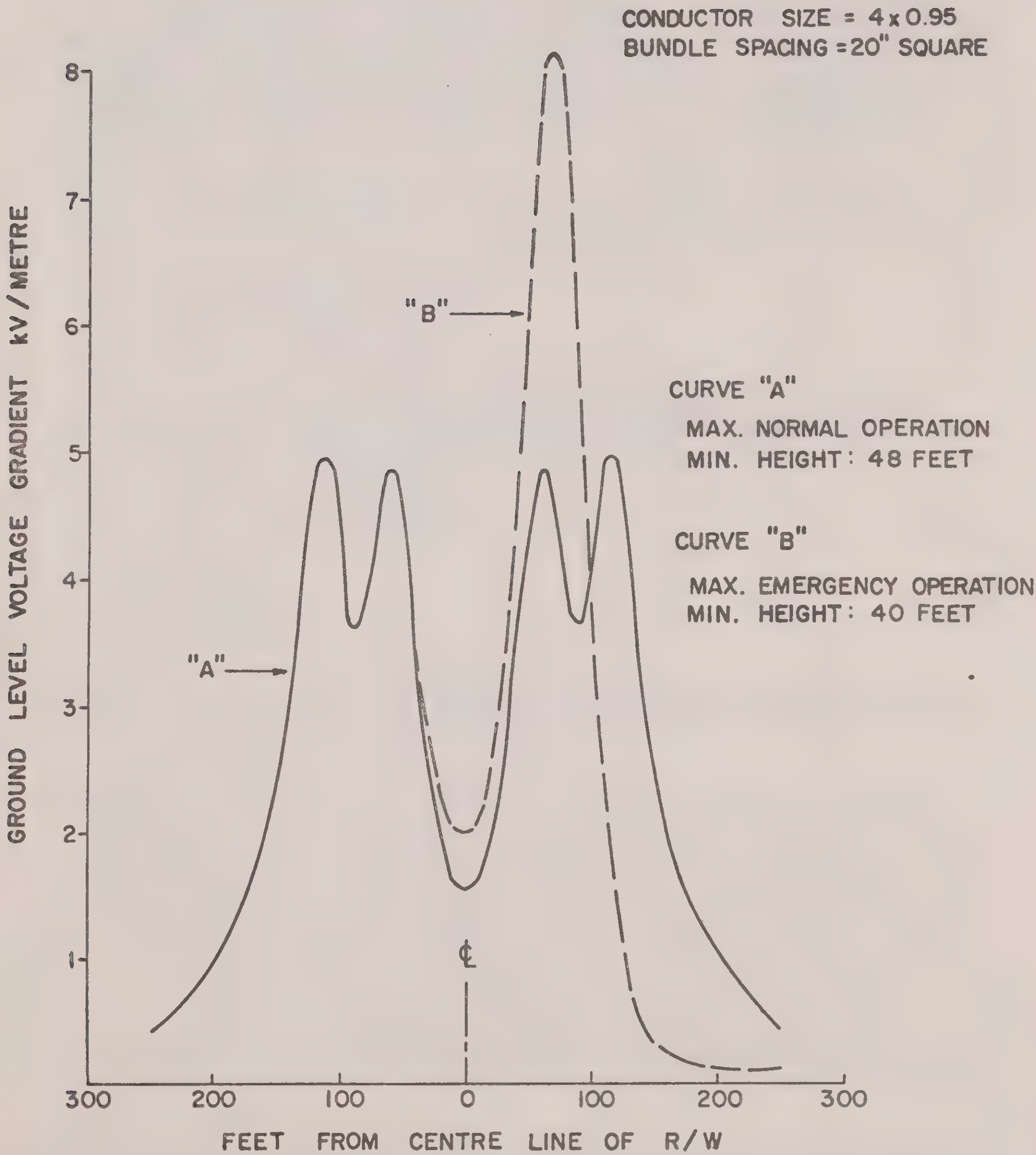

FIGURE 9

Appendix 8-D

Transformer Station Insulants

A. SF6 Switchgear

Ontario Hydro is completely satisfied that no risk is being imposed on its own employees or the public by the use of SF6 gas in Transformer Stations. The Institute of Environmental Studies of the University of Toronto has stated that the health hazard associated with the SF6 gas insulated stations would be negligible. This view is supported by the Ministries of Environment, Health and Labour.

Some of the outstanding properties of SF6 which make its use in power applications desirable are:

- arc-quenching ability
- thermal stability
- thermal conductivity.

In addition to these electrical and thermal properties, SF6 has many physical and chemical attributes which make it a suitable dielectric for the power industry.

Sulphur Hexafluoride is:

- chemically inert
- nontoxic
- nonflammable
- noncorrosive

A 100% concentration of SF6 gas would cause suffocation but that is true of any inert gas including nitrogen which makes up 80% of the air we breathe.

Nitrogen, carbon dioxide and hydrogen are used in large quantities in many processes without undue risk to workers in the plant. The chance of anyone being exposed to a 100% concentration of SF6 gas is almost nil. Any gas which escaped from the switchgear would gradually diffuse into the air and be dispersed by the building ventilation system. Any particular switchgear is divided into hundreds of compartments mainly to facilitate maintenance without replacement of more than the minimum amount of gas. Even the worst credible accident would not result in the simultaneous escape of the gas from more than a few of the compartments.

SF6 gas when exposed to an electric arc can be decomposed. The decomposition products include the lower fluorides of sulphur.

The amount of SF6 that would be decomposed in any one compartment of the SF6 switchear, if an arc should occur

in that compartment, would depend on the arc current and the duration of the arc, i.e. the amount of energy released. Even in an extreme case, it would only be a small portion of the total volume of gas in the compartment. If the pressure relief diaphragm did not rupture, the contamination would be contained within the compartment but would not affect the future operation of the equipment. If the diaphragm did rupture, the decomposition products would, of course, be released. The volume would be extremely small, however, compared to the volume of the switchgear room and would not constitute any hazard to personnel. This minute amount of decomposed gas would eventually be exhausted into the atmosphere by the ventilation system. The concentration of these potentially obnoxious and/or toxic materials so vented would be a far less serious an environmental pollutant, than say the exhaust from cars passing on the street. Ontario Hydro is not aware of any arc on any of the 100 SF6 switchgear stations in operation that has caused a rupture of an explosion vent diaphragm. In a telegram dated Feb. 9, 1976, one of the largest manufacturers states that in 300 circuit breaker years of equipment operation, there have been no arc failures of any kind on their equipment.

Within the circuit breakers units of the switchgear, a controlled arc of very short time duration is formed each time the breaker is opened when carrying current. In fact, one of the principle advantages of the SF6 circuit breakers is the ability of SF6 to extinguish this arc, and hence interrupt the current quickly. On each such breaker opening, some very small amount of gas decomposition will therefore occur. Enclosed in each breaker compartment is a quantity of an activated alumina-soda lime mixture which readily absorbs these decomposition products to ensure repetitive breaker operation. Tests carried out in France showed that after over 500 separate breaker operations, at currents covering the range one might expect in service, that is, after a breaker lifetime of operations, only 1/4 of 1% of the SF6 had been decomposed and the ability of the activated alumina-soda lime to absorb the decomposition by-products had been less than half utilized, i.e. decompositon products for another life of the breaker could be absorbed with still some margin.

A French paper titled "Practical Consequences of Research on the Decomposition by Arc of SF6" by Jean AMALRIC et al published in REVUE GENERALE DE L'ECTRICITE, JUIN 1974, "Numero Special" gives further data on the use of SF6 gas in power system switchgear.

Use of sulphur hexafloride is not new to the industrial environment. Besides being utilized in the elect apparatus, it can be introduced as a blanket gas, similar to that of pure nitrogen, in the manufacturing process of manganese to prevent oxidation. There are at least two

firms in Ontario using this gas and workers are exposed daily without any adverse symptoms.

The toxic property of sulphur hexafluoride was first investigated in 1950, and findings were reported in the Archives of Industrial Hygiene and Occupational Medicine (Ref 8D(1)). During the experiments, rats were exposed to a concentration as high as 80% for 16 to 24 hours. No adverse health effects were observed. These findings were confirmed by another independent study in 1953. The Chemical Threshold Limit Value Committee of the American Conference of Governmental Industrial Hygienists, a body consisting of well-known toxicologists, occupational physicians, engineers, and chemists, concluded that this gas is physiologically inert. Repeated exposures by humans at 1000 parts per million (0.1%) or below for 8 hours a day would not constitute a health hazard (Ref 8D(2)).

The data published by the Threshold Limit Value Committee are based on the best currently available information from industrial experience, from experimental human and animal studies, and when possible from a combination of the three. These values are determined with the objective of protection against impairment of health, irritation, narcosis, nuisance or other forms of stress, and these limits are offical documents applied throughout the United States as well as in Canada, especially in Ontario.

Another experiment was carried out by the University of Paris in 1967 where groups of rats inhaled 80% decomposed gas and 20% oxygen for 1 to 2 hours. The exposed animals presented no respiratory difficulties or changes in behaviour; mortality remained zero. Examination 24 hours later did not reveal any pathological lesion of the lung tissues.

B. PCB Compounds

Some types of major equipment at stations use an insulant of a synthetic non-flammable liquid of a non-biodegradable, polychlorinated biphenol (PCB) compound known commercially as askarel. Outdoor capacitor banks and indoor transformers at stations are the main examples. Its use in capacitor banks is because of its highly desirable electrical characteristics which are not presently attainable with alternative insulants, while for indoor transformers it is because of the fire resisting characteristic.

Special measures are taken to protect the environment from this liquid. Provision is made to catch any accidental leakage such as at new capacitor locations by use of a sand trap with polyethylene liner. Procedures have been implemented that require regular inspections. The faulted equipment together with all contaminated materials are

sent to approved disposal facilities in sealed metal containers.

C. References

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APPENDIX 10-A

The Methods of Handling Certain Factors in Cost Comparisons

A. Discount Rate

At the present time, the rate is assumed to be best represented by Hydro's expected interest rate for long-term borrowings. In practice, the discount rate is periodically reviewed in the light of current economic forecasts and revised as necessary.

B. Life Expectancy

The point at which physical plant must be retired from service and replaced with other facilities is important in economic cost comparisons. This is because it determines when payments must be made for replacements and it plays a part in determining the future period during which costs can be influenced by a current decision. Life expectancy depends on physical deterioration and technological obsolescence. It does not depend upon accounting cost allocation considerations (i.e., not upon depreciation periods used for accounting purposes).

C. Escalation and Inflation

To ensure that estimated cash flows are realistic, escalation forecasts are applied to cost estimates. These forecasts are prepared annually, or more often as warranted by changing forecasts of economic conditions. An outline of the approach used in forecasting is given in Section 10.4.

D. Interim Replacements

The costs for replacing or rehabilitating some components of generation plant prior to the end of its useful life should theoretically be included in the cost of generation alternatives. Generally, in Ontario Hydro studies, these costs are not included because they are negligible in relation to total costs, and hence do not justify the extra estimating effort.

E. Insurance

Insurance carried by Ontario Hydro includes construction insurance covering Ontario Hydro and contractors against

liability arising from accidents during construction, and insurance covering damage to some major system components. Generally, in Ontario Hydro studies, these costs are not included because they are negligible in relation to total costs.

Public liability insurance for nuclear plants is currently carried by AECL and hence has not in the past entered into alternative generation comparisons since it did not represent a payment for resource acquisition by Ontario Hydro. This situation is expected to change upon passage of Bill C 158. Ontario Hydro is therefore negotiating with the government and insurance carriers to determine the charges.

F. <u>Taxes</u>

Ontario Hydro is not subject to federal and provincial income taxes. In this area, Ontario Hydro's economic cost comparisons differ from those carried out in private industry, where tax credits resulting from payments associated with the acquisition of resources are a major concern. Property taxes and sales taxes (both provincial and federal), are paid by Ontario Hydro, and they are included in comparisons in which they give rise to significant differences.

G. <u>Operations and Maintenance Costs</u>

These are resource acquisition costs and where they are significant they are included in economic comparisons. They include both direct costs and allowances for overheads which vary in proportion to them, such as sickness, accidents, and vacation and holiday time.

H. <u>Inventories</u>

Inventories influence costs by causing a difference between the time of acquisition of the resource and the time of the use of a resource by Ontario Hydro. Approximations such as average costs may be used as the cost of items drawn from inventory.

I. <u>Commissioning Costs and Energy Credits</u>

Since all significant costs must be included in an economic cost comparison, commissioning costs, which represent payments for resources acquired by Ontario Hydro, form part of alternative economic comparisons. Where appropriate, the net commissioning costs include credits for the energy supplied to the electrical system during the commissioning phase, because

this reduces the energy that must be supplied by the remainder of the system.

J. Overheads

Overhead costs, are costs such as administration and supervision which are only partly affected by direct costs such as construction labour. Insofar as they are not directly related to a choice between alternatives they are treated as common costs. Forecasts of the portion of overhead costs which will be directly affected by a choice between alternatives are applied as percentages to operation and maintenance and initial facility costs.

K. Equivalent Uniform Annual Costs (EUAC)

These are equal yearly amounts having the same present worth when discounted as the cash flow payments associated with an alternative. They are occasionally used to compare projects having different economic lives when like-for-like replacement is expected. However, their use is usually avoided in comparisons of major facilities because of the potential for confusion with allocated costs.

L. Sale of By-Products

Differences in receipts from the sale of by-products are a factor in economic efficiency, but they are ignored in studies if they are negligible in comparisons with total costs. For this reason, a simplifying assumption is made that the cost of dismantling plant at the end of its life will be equal to inflows from its sale as salvage.

M. Risk (Sensitivity Analysis)

Since costs must be realistic, forecast cash flows associated with resource acquisition are based on the "most likely" estimate, i.e., that which has the highest probability of occurrence.

Sensitivity analysis is a technique which is used to identify those key factors which are the principal contributors to the risk that an inferior alternative will be chosen. In this technique the estimates which have the greatest impact on the comparison are identified, usually by changing each one in turn by a given proportion, e.g. 10%. Then the effect on the comparison of varying these estimates through a range of values (e.g. from a minimum to a maximum) based on possible inaccuracies in forecasts and assumptions is investigated.

Those estimates that significantly change the comparison when varied through this range of possible values are candidates for additional estimating effort directed toward reducing the range. In addition, the discount rate is varied to ensure that comparisons are valid under a wide range of economic conditions.

N. Heavy Water Costs

Acquisition costs of heavy water are included in the initial costs of generation facilities. Using the simplifying assumptions associated with the acquisition of items from inventory, the average cost at the time of facility construction is used. Under simplifying assumptions, no terminal value is assigned to the heavy water at the end of the life of a nuclear station.

APPENDIX 10-B

Financial Objectives of Ontario Hydro and Their Effect on The Comparison of Generation Alternatives

A. Financial Objectives of Ontario Hydro

The final allocation of costs to Ontario Hydro customers is determined with several objectives in mind. Some main objectives are:

(a) to obtain funds at minimum cost,

(b) to allocate costs equitably between classes of customers,

(c) to allocate costs equitably between present and future customers,

(d) to avoid sharp year to year variations in rates.

The mechanism used to attain these objectives, and its relationship to the selection of alternative plans for system development are outlined in this Appendix.

B. Forecasting the Impact of Alternative Plans Upon the Cost of Power

The system used to arrive at the cost of power is complex. It starts with the recording of all payments by Ontario Hydro to outside organizations and individuals (including staff) for goods and services. To the extent required by financial policy, payments are related to the physical system used to generate and deliver energy before being allocated to customers. Remaining items such as some administration costs are allocated without reference to physical plant.

Payments are identified as either capital or expense. The former are allocated to customers over a number of years in accordance with depreciation policy. The latter are allocated during the year in which they occur.

In addition to allocating payments, the costing system includes an equity charge designed to maintain an appropriate level of financial soundness. This amount is appropriated to debt retirement and/or system expansion.

Before the cost of power is translated into a rate structure, modifications may be made in order to smooth out year to year variations.

The manner in which payments resulting from implementation of alternative plans for system expansion will be allocated to the cost of power, is not a matter of concern when alternatives are being compared. At the comparison stage the emphasis is on determining the alternative requiring the lowest payments, that is, on economic efficiency. If it is concluded that this emphasis will make the achievement of financial objectives difficult a suitable restriction is imposed. The restriction on high capital alternatives is an example.

C. <u>Differences Between Incurred and Allocated Costs</u>

Use of the same terminology for both incurred and allocated costs sometimes leads to misunderstanding of intent. Some examples are discussed in the following sections.

(a) <u>Interest</u>

In economic cost comparisons the term "interest rate" is sometimes used interchangeably with "discount rate" to identify the time-related value of resources. In cost of power allocations "interest rate" refers to interest on borrowing. The two are only indirectly related. At any given time there is only one time-related value of resources appropriate to Ontario Hydro as a whole. On the other hand, at any given time interest charges to be allocated to the cost of power are the result of a great many different interest rates.

(b) <u>Depreciation</u>

When referred to in economic cost comparisons depreciation identifies the loss of value of an asset. Depreciation leads to economic costs for replacements or repairs but is not in itself a cost. Depreciation charges under the cost allocation system, on the other hand, are used to recover the original cost of an asset in a manner consistent with financial policy.

(c) <u>Overheads</u>

Overheads in economic cost comparisons are indirect costs, such as management and legal costs which will be influenced by the choice of alternative. Because indirect costs tend to be almost the same regardless of the alternative chosen overheads are seldom a significant cost comparison factor. Overheads in cost allocation usage are also indirect costs but since all costs must be recovered, regardless of whether they will be different, they can be much more significant in this context.

(d) Annual Costs

Expected incurred costs are sometimes, for economic comparison purposes, converted to equivalent uniform annual costs using the discount rate to take timing differences into account. Such costs are never the same in amount and timing as the annual cost allocations that will be made in order to recover capital costs, and only the same as the annual cost allocations for expenses when there is no significant escalation.

(e) Capital Cost of Nuclear Fuel

For economic cost comparisons the cost of nuclear fuel is taken into account by estimating the time and amount of payments for acquisition of the fuel from suppliers. No allowance is made for the value of spent fuel. For cost allocation purposes, one half of the cost of the initial charge of fuel is allocated as a part of the capital cost of the nuclear plant. All other nuclear fuel costs are identified as expenses. The pattern of the costs used for economic cost comparisons and for allocation will therefore, be quite different.

APPENDIX 10-C

The Steps Followed by Ontario Hydro in Producing Its Economic Forecasting Series

A. Data Collection and Mathematical Manipulation

Various types of data are collected by the Office of the Chief Economist and other Ontario Hydro groups, which form inputs to the forecasting process. Some of this data (mostly Statistics Canada historic indexes) is regularly added to a Forecasting computer data file for later manipulation. The types of data could be categorized as follows:

(a) Historic records and indexes, either developed internally or published by outside sources.

(b) Opinions, advice and conclusions of internal and external "experts" in all pertinent areas (labour, fuel, materials, commodities, manpower, foreign exchange, economic indicators, etc.)

(c) Various economic publications, articles and news reports.

(d) Econometric models.

The assimilation of this data is not currently a fully formalized process. Generally speaking only internal cost records and certain externally published indexes are recorded in series form for future use. All other data is retained either in its originally published form or mentally by the people concerned. In an effort to relieve this problem and with an end result of being able to provide "immediate" retrieval of economic data, Ontario Hydro's Economic Projections and Services Group is developing and will maintain an Economic Information Unit. Here all background material for forecasts will be stored as well as common economic data needed by the rest of the Ontario Hydro organization.

The Information Unit has begun using Cansim, a Statistics Canada computer data bank which contains thousands of time series. This usage is through a remote terminal on external time sharing computer services, from which instant retrieval is possible. Further, the Information Unit is endeavouring to physically maintain other economic information which is required on a high priority repetitive basis by the Division.

The output and use of the econometric model, Candide, was purchased in late 1974 to provide a mathematical projection of important economic variables. This is a large, and well regarded model, and is one of the few which project beyond 1 or 2 years. The service company selling it also arranges

semi-annual user meetings to discuss assumptions built into the model, and modifications are made to reflect the group's consensus views. These meetings also provide very useful opportunities for establishing contacts with other private and public sector practicing economists.

Efforts have been made to establish contacts with large utilities for the purposes of exchanging information on forecasting techniques and data. Regular contact is kept with such companies as Quebec Hydro, Manitoba Hydro, B.C. Hydro, AECL and Bell Canada. Other contacts are now on an "as need develops" basis.

Each forecast category has a "Historic Data Base and Composition" listed. These are descriptions of the historical data series which make up the categories, and should reflect the actual movements in them. Most component parts of each "data base" are on the computer data files for use in later manipulations.

Mathematical projections are produced for all the historic data base series. Two curve fitting techniques are utilized, with the calculations being performed on the computer. The computer programs were produced by the Economist in Charge of Load Forecasts and are the same ones used in deriving the Load Forecast. The projection results are described below:

(a) Least Square Technique - produces a forecast rate of change per year based on an equal weighting to each piece of historical information regardless of its date of occurrence. Such a projection represents a long-term growth rate.

(b) Exponential Smoothing Technique - produces a projected rate of change based on more weight to recent data than to older data in the series. This projection represents a short-term growth rate.

Further, 3, 5 and 10 year compound average growth rates are calculated for each series.

B. <u>Data Interpretation into Future Economic Assumptions</u>

Much of the data collected and manipulated undergoes subjective analysis leading to a series of economic, political and sociological assumptions about the future. These assumptions are developed on a "most probable" basis, that is, they are felt more likely to transpire than any other scenario of events. The assumptions themselves are very interrelated, and dependent on each other over time. Most major economic variables are considered in this interpretation process, with

the analysis effort first considering the international situation, followed by the national, provincial and special industry sectors. The final time-related assumption series represents the consensus view.

C. Interpretation of the Assumptions and Data into Forecasts

The economic assumptions developed are summarized and presented to an Advisory Committee, consisting of members from Comptrollers, Fuels, Design and Development, Labour Relations, Stations Transmission and Distribution, Supply and Treasury Divisions. Here assumption consistency, impact on specific areas of Ontario Hydro, and additional data requirements are discussed. Additional forecast inputs are provided by group members when required.

In this stage of the process all information thus far produced is utilized along with new, more detailed local data. Interpretation of all this information leads to the series of figures published. The new data inputs relate to the specific cost categories, rather than the general variables considered in the assumptions. An example would be, the assumptions define what will happen to industrial wage rates in general, but the forecast must reflect the movement of Ontario Hydro's wage rates which are influenced by local exogenous variables. Such things as the union contract, Ontario's employment situation and Ontario Hydro's wage policies become very important, especially in the first 5 years.

Effectively, a judgmental process is carried out, which results in the forecast figures. The following steps suggest the general parameters followed for each cost index:

(a) Consider mathematical projections of historic data. (This must be done in terms of the type of economy which produced the information vs the expected economy as defined in the assumptions.) These mathematical projections provide a limited, but useful, interpretation of the historic trends. Acceptance of these projections as the anticipated sequence of events implies an assumption that the economy of the future will be exactly the same as it was in the past.

(b) Consider new detailed data.

(c) Consider assumptions.

(d) For years 1 and 2 decide on variance necessary from the exponentially smoothed projections.

(e) For years 1 to 4 decide on the figures indicated by the assumptions.

(f) For the long-term (years 11+) consider the least squares projection, all assumption data, and "local" data. Decide if least squares is applicable, or the variance therefrom.

(g) For years 4-7 to 10 determine annual projections in a descending or ascending order of magnitude from the years 4-7 rate to the long-term rate, unless the assumptions indicate another pattern.

(h) Determine consistency between all indexes and re-cycle through above process when necessary.

D. Fuel Cost Forecasting

Introduction

Due to the recent massive structural changes in primary fuel markets, forecasting of fuel costs using simple mathematical projections is no longer valid. The present procedure, therefore, has a large judgmental input taking advantage of as much hard data as is available. The underlying emphasis is to achieve a disciplined approach to assessing the most probable fuel cost levels as they will apply to Ontario Hydro.

Source Data

Background data is assembled by the Fuels Division staff throughout the year from the following sources.

(a) Main Sources

i) Actual prices paid under existing contracts for fuel, transportation, storage, etc.

ii) Estimates of future prices from negotiations of future contracts with particular emphasis on market conditions and fuel characteristics.

iii) Liaison with and data resources of Energy Boards and Regulatory authorities.

iv) Discussions with vendors and knowledgeable individuals in industry, universities and government.

(b) Subsidiary Sources

i) Trade Publications and selected press intelligence.

ii) Technical papers published in professional journals. Authorities.

iii) Policy statements by government leaders.

iv) Attendance at conferences and seminars on energy economics.

v) Analysis of the effects of relevant union negotiations.

(c) Trends in the Economy

The above sources are augmented by consultation with the staff of the Office of the Chief Economist on general trends in the economy, including economic projections produced by this group. In particular, the inflation figures used in the forecast are obtained from this source.

(d) Calculations

Starting out with:

- existing prices

- key assumptions which reflect the most probable future based on current judgement of developments in fuel markets and technology, and

- the inflation figures mentioned above.

The expected future costs to Ontario Hydro are calculated. Detailed calculations are carried out for periods of up to 10 years, depending on the fuel. Beyond these time periods, the uncertainties become so great, that they preclude any attempt at accurate, individual fuel-cost forecasts. Therefore, to ensure fuel-cost forecasts are consistent with the projection of other cost elements and to maintain the underlying assumption of relativity, a simple annual percentage increase, keyed to the long-term inflation rate, is used across the board.

The results of all calculations are assessed within the Fuels Division for mutual consistency and adjusted where necessary.

The Ontario Hydro forecast and those of external authorities are compared, usually on a non-formal basis, any differences examined and modifications made if warranted.

Finally, an advice is prepared which details the basic assumptions behind the forecast and highlights any significant changes in the fuels area. The forecast is

then issued to those requiring the information. In addition the Office of the Chief Economist converts the data contained in the advice to an index basis and issues them together with the other escalation indexes.

E. Production and Distribution

After the forecasts have been derived, they are discussed by the professional staff of the Office of the Chief Economist and adjusted, if necessary, after consultation with the relevant individuals. The final forecasts are then sent to printing. After the forms are printed they are distributed throughout the organization with a short cover memo. Approximately 260 copies are sent out.

APPENDIX 12-A

Load and Generation Balance

As discussed in Section 12.5 D, the basic system planning criteria call for the system to be tested at the most severe expected load and generation conditions. For the purpose of this study, conditions tested are as follows:

(a) In areas in which the installed generation is in excess of the load and less than about 30% of the total projected East System December peak load, the system is tested with the output from generation in the area equal to full output from all of the installed thermal generation plus hydraulic generation for median water conditions and the load level at 85% of December peak load.

(b) In areas in which the installed generation is in excess of the load and more than about 30% of the total East System December peak load, the system is tested for the most onerous of the following conditions:

   i) With the load level at 85% of the December peak load and with the area generation at an output equal to 30% of the East System peak load.

   ii) With peak load levels and with the area generation at a level required to supply the demand with the generation in the remainder of the system operating at an output estimated to be available 98% of the time.

(c) In areas in which the installed generation is greatly in excess of the load and more than about 30% of the East System December peak load, the system is tested for the most onerous of the following conditions:

   i) With the load level at 85% of the December peak load and with the area generation at an output equal to 30% of the East System peak load.

   ii) With peak load levels and with the area generation at a level required to supply the demand with the generation in the remainder of the system operating at an output equal to 70% of the installed thermal generation plus hydraulic generation for median water conditions.

(d) In areas in which the installed generation is in excess of the load, the system loadings may be heaviest at other than peak load conditions. The following conditions are checked:

   i) Full output of all fossil generation on any one site at all East System load levels above 70%.

ii) Full output of all nuclear generation on any one site at all East System load levels above 50%.

iii) Full output of all nuclear and hydraulic generation (freshet level) in any area at all East System load levels above 50% unless the amount of nuclear and hydraulic generation in the rest of the system makes this criterion unnecessary.

The operating levels specified in (a), (b), (c), and (d) are such that in our judgement there will be a reasonable probability that generation will not be "locked-in", that is most of the time it can be operated at levels of output required by the load or for economic operation of the system.

(e) In areas where the amount of generation installed is less than the peak load, the system is tested with the thermal generation output at a level estimated to be available 98% of the time and with the combination of load level and hydraulic generation which results in the largest transfer into the area.

APPENDIX 12-B

Method to be Used in Identifying Environmental Implications of Transmission System Alternatives

A. General

In a subsequent report to the Commission, Ontario Hydro will provide a comparison of the environmental implications of alternative conceptual plans for the East System. The method which will be used to identify the environmental implications of the transmission system alternatives is described in this Appendix. This method will facilitate:

(i) The production of maps depicting geographic variation in environmental constraints to transmission facilities within that portion of the province defined by the East System;

(ii) The delineation, for each alternative East System plan, of "bands" - broad, linear areas within which the probability of finding environmentally acceptable locations for the transmission facilities required by a particular system plan appears greatest in light of the identified constraints;

(iii) The identification of the potential environmental implications of locating the required transmission facilities in the "bands" delineated for each alternative system plan.

B. Identifying Bands

The system plan forms the basis for defining the termination of the transmission line. Bands will be identified either by avoiding areas which present the greatest environmental constraints to transmission facilities, crossing those areas on or adjacent to existing severances, or impinging upon areas having a high level of constraints only where essential from a technical or economic standpoint. Areas of greatest constraint will be identified according to one or more of the following criteria:

(i) An officially stated and provincially approved land use restriction, plan or policy which would be violated by the imposition of transmission facilities;

(ii) An environmentally imposed engineering problem, the satisfactory solution to which would result in substantial extra installation, operation or maintenance costs;

(iii) The liklihood that transmission facilities would cause provincially or regionally significant detrimental changes in the area or in the activities of the people who inhabit or use the area, now or in the foreseeable future.

To facilitate the kind of decision which must be made in identifying "bands", that is where generally within the province could the transmission facilities required by a particular system plan best be located, it was judged appropriate to consider the potential effects of transmission facilities on those factors which contribute, or could contribute in the future, in a major way to the provincial or regional quality of life. Accordingly, factors will be considered in the following categories:

(i) Stated and approved land use restrictions, policies and planning objectives:

(ii) Urban development providing residential, industrial, commercial and institutional facilities;

(iii) Availability, quality, utilization and management of natural resources for food production, timber production, mineral extraction, recreational and cultural activities, etc.;

(iv) Life supporting ecological processes and major components of natural ecosystems;

(v) Appearance of the landscape.

Five procedural steps are being, or will be, employed to implement the above approach to identifying bands:

(i) <u>Inventory of the East System Study Area</u>

Information is being collected on a variety of parameters, or data variables, and mapped at a scale of 1:250,000 to depict geographic variation throughout that portion of the province lying south and east of Lake Nipigon in characteristics related to one or more of the factors under consideration.

This generalized, continuous-line mapping will effectively subdivide the study area according to each parameter into smaller areas of differing description (e.g. Figures 1 to 4). For ease of handling, the mapped information is being manually encoded or digitized and computer stored on the basis of a 2 x 2 km, U.T.M. registered grid.

(ii) <u>Identification of Objectives</u>

Recognizing that a primary intent of band identification is to avoid areas of greatest environmental constraint wherever possible, a number of specific objectives are being prepared with respect to each factor by professional environmental analysts, planners and others with specific expertise related to that factor. Each objective will comprise:

- A directive to avoid a particular type of area characterized by specific descriptive information contained within the inventory;

- An appended "because" clause outlining reasons why such areas should be avoided, in terms of the changes which might be expected if transmission facilities were to be located there and the perceived significance of those changes.

(iii) Ranking Objectives

To facilitate ranking the identified objectives in order of the relative priority to be given to the respective avoidance directives, each objective will be recorded on a separate card. The cards will then be ordered on the basis of a comparison of the "because" clauses, particularly that information regarding the significance of the anticipated changes.

(iv) Identification of Constraint Areas

In general, areas of differing levels of constraint can be identified by applying the literal directives of the objectives, in the established order of priority, to the description of the study area (i.e. the mapped inventory). The computer will be instructed to search the entire study area for, and so designate: first, all 2 x 2 km grid cells which exhibit the characteristics of the type of area described in Objective 1 on the priority list; second, all cells which exhibit characteristics of the type of area described in Objective 2; and so on, in order, until each cell within the study area has been designated according to the highest ranked objective which can be applied thereto (as exemplified in Figure 5). To facilitate simple graphic display of the differing degrees of environmental constraint occurring in the study area, the objectives will then be grouped into a few levels so that the total area (i.e. number of cells) to which objectives in each level apply is approximately equal (Figure 6).

(v) Delineation of Bands

By using the simplified constraint map as an initial guide as to the environmentally "best" and "worst" areas to locate transmission facilities, general locations of bands to accommodate each alternative system plan will be identified by coarse visual inspection. To delineate the approximate boundaries of the bands, and to indicate where bands might best traverse areas of relatively high constraint when necessary, the general band locations will be checked against individual cell designations regarding the highest ranked objective applicable thereto and against the individual inventory maps. Figure 7 shows an example of band delineation.

C. Identifying Implications of Locating Transmission Facilities Within Bands

The bands so delineated for any East System alternative will comprise a network (or alternative networks) of broad pathways through the study area wherein the probability of finding environmentally suitable locations for the required transmission facilities appears greatest. However, all potential environmental problems will not have been overcome. Therefore, it will be necessary to identify for each system alternative (i.e. for each network of bands) the probability of incurring those potential environmental effects which persist within the relevant bands - the potential environmental implications of locating transmission facilities within the bands delineated for each system.

These implications will be expressed:

(i) In tabular form, in one or more of the following ways:

- The success with which a given plan satisfies each environmental objective, with particular emphasis on those objectives of highest priority;

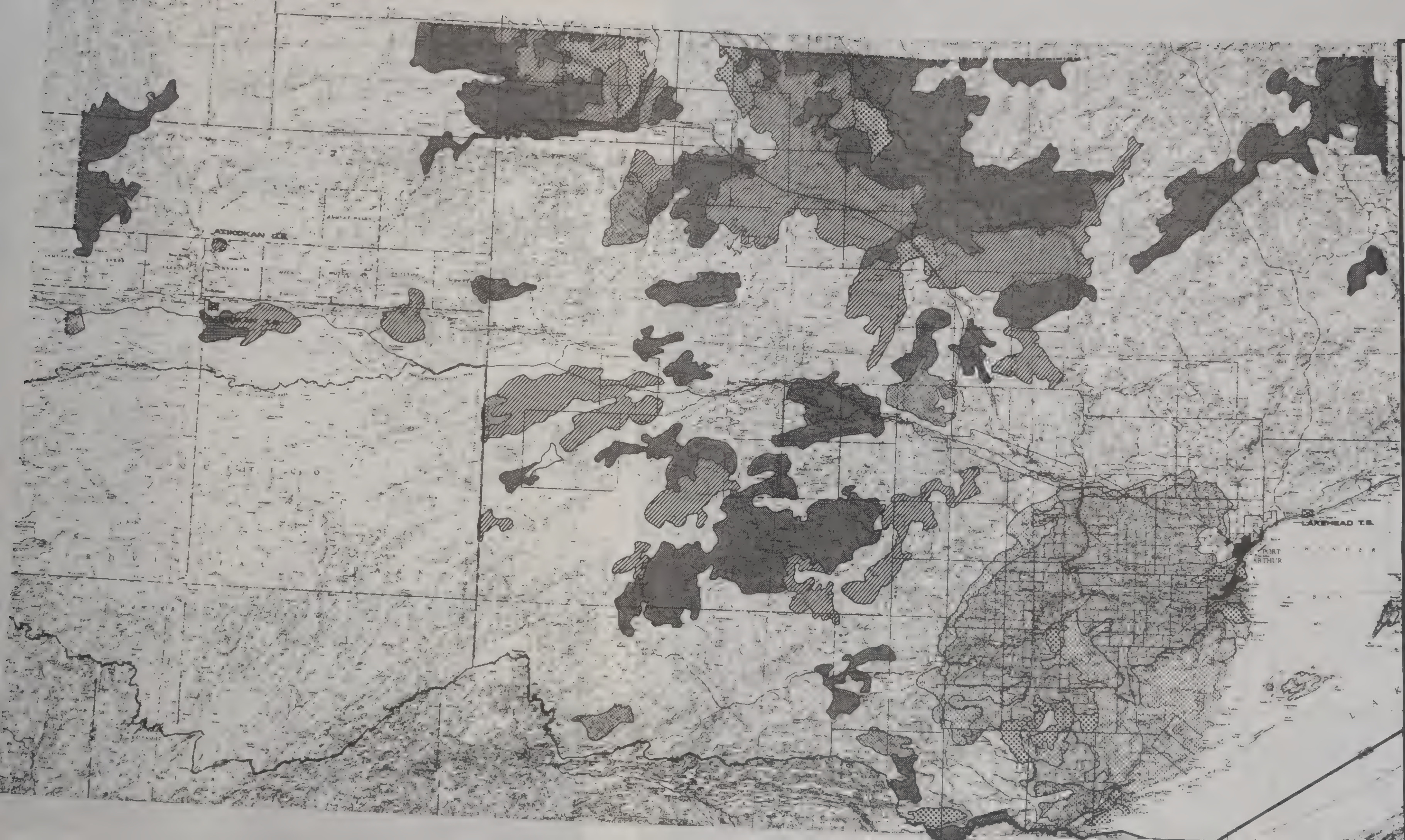
- The probability (or risk) of a given plan violating each environmental objective or impinging upon specific environmental situations relating to each factor;

- The probable extent of such violations or impingements expressed in linear, area, volumetric and/or economic terms, if and where possible;

- The significance of such violations or impingements, particularly as regards their potential present and future limiting effects on major contributors to the quality of life of Ontarians.

(ii) In graphic form by superimposition of the bands to accommodate each plan over constraint, factor and inventory maps.

When tabulated for each system alternative, with technical and cost implications, and with similar implications of locating generation facilities in appropriate zones, and simplified to reflect only uncommon environmental, technical and economic costs and benefits, this information will provide a basis upon which alternative plans for the East System can be compared and evaluated.



ROUTE SELECTION STUDY FOR W 2 (MARMION LAKE SITE)

FOREST SPECIES ASSOCIATIONS

- HARDWOOD POPLAR - WHITE BIRCH
- MIXED POPLAR - WHITE BIRCH
- MIXED POPLAR - WHITE BIRCH (70 %) - BLACK SPRUCE (30 %)
- WHITE SPRUCE - BALSAM FIR - POPLAR - WHITE BIRCH
- WHITE SPRUCE - BALSAM FIR - POPLAR - WHITE BIRCH (70 %) - BLACK SPUCE (30%)
- JACK PINE
- JACK PINE (70 %) - BLACK SPRUCE (30 %)
- BLACK SPRUCE

REVISION	DATA SOURCE
	- ONTARIO LAND INVENTORY "LAND CLASSIFICATION MAPS" 52A 52B 52G AND 52H - ONTARIO MINISTRY OF NATURAL RESOURCES (M.N.R.) 1973 SCALE 1 250 000 - DISCUSSIONS WITH MNR PERSONNEL OLI PROGRAM

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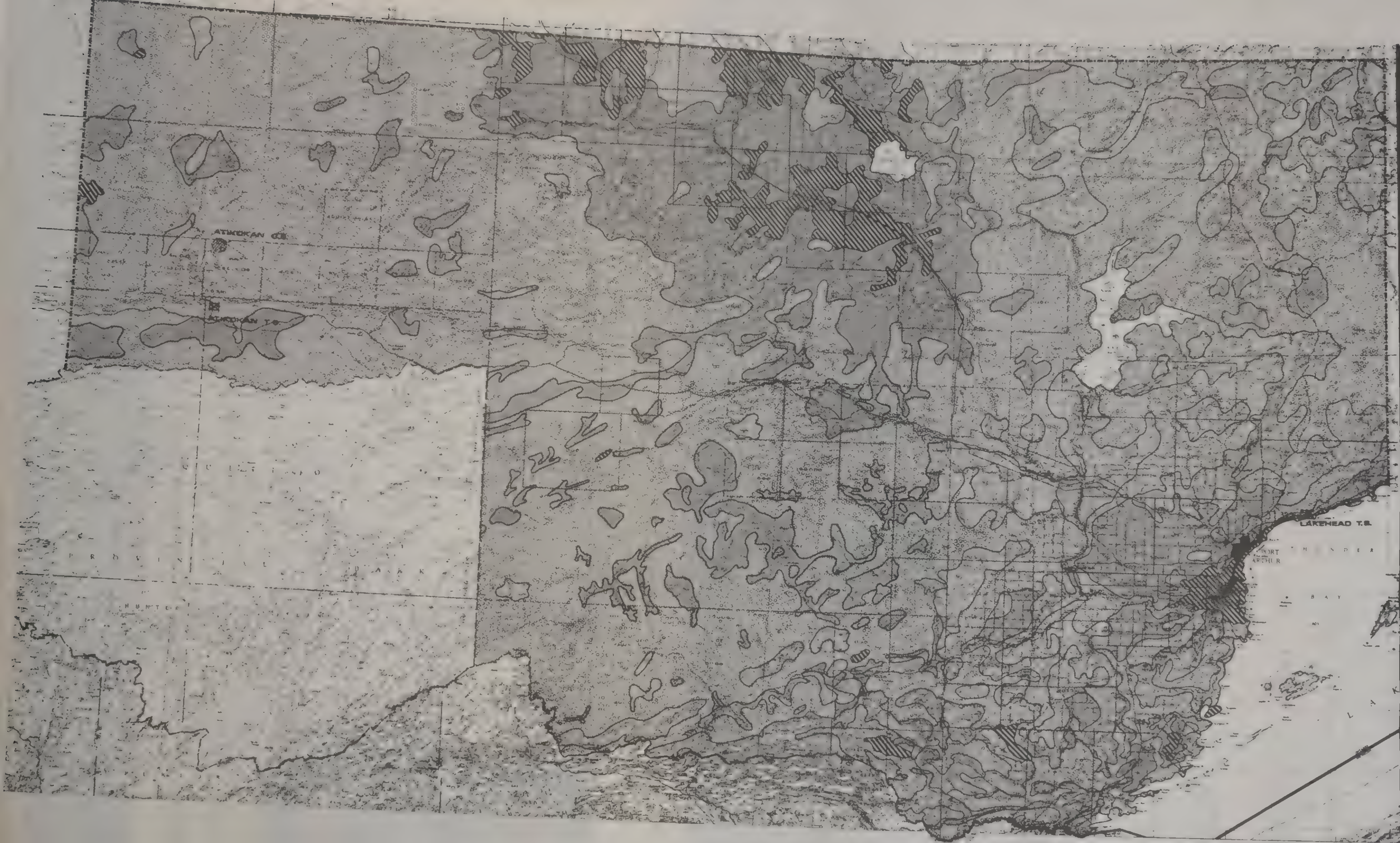
Figure 1



ROUTE SELECTION STUDY
FOR
W 2 (MARMION LAKE SITE)

TOPOGRAPHY

- FLAT (0-15% SLOPE)
- ROLLING (15-30% SLOPE)
- HILLY (30-60% SLOPE)
- VERY HILLY (60% + SLOPE)

REVISION	DATA SOURCE
	BLACK AND WHITE AERIAL PHOTOS [illegible] AND 1972 NATIONAL AIR PHOTO LIBRARY ENERGY, MINES AND RESOURCES OTTAWA SCALE 1 [illegible] ([illegible]) 1 40 000 (1972)

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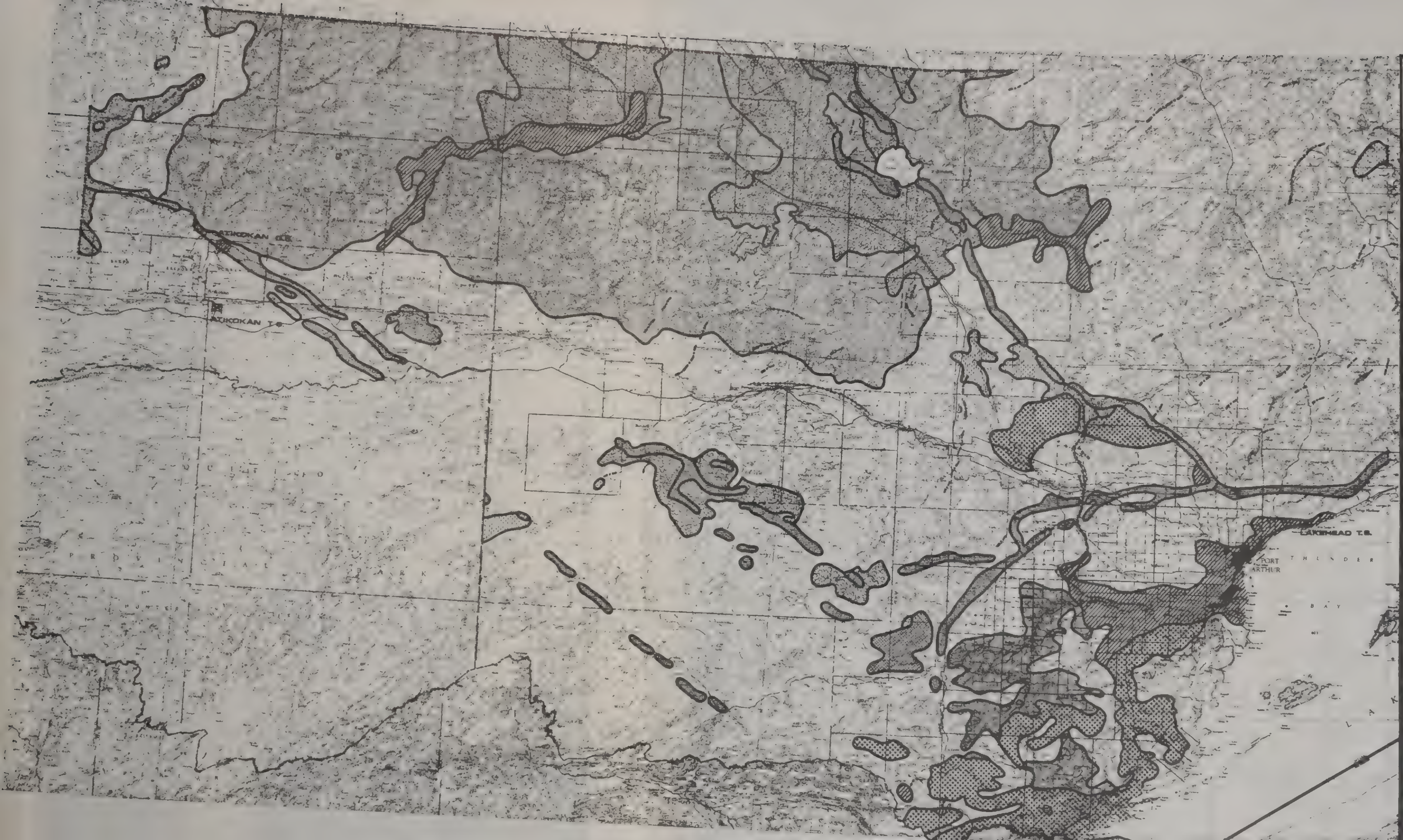
MAP SERIES NUMBER

Figure 2



ROUTE SELECTION STUDY FOR W 2 (MARMION LAKE SITE)

PHYSIOGRAPHIC FEATURES

- MORAINE SAND & GRAVEL, MODIFIED BY LAKE ACTION
- MORAINE UNMODIFIED
- SPILLWAYS
- KAME & ESKER DEPOSITS UNMODIFIED SAND, GRAVEL AND BOULDERS
- TILL SILTY TO SANDY
- LOESS FINE SAND OR SILT WITH SOME OUTWASH
- TILL CLAY
- LACUSTRINE CLAY & SILT WITH SILTY SANDY TILL
- LACUSTRINE SAND WITH SILTY SANDY TILL
- DELTAIC SAND AND VALLEY TRAINS
- OUTWASH SAND, FINE SAND, GRAVEL
- BARE ROCK ERODED BY LAKE ACTION
- ESKERS

REVISION	DATA SOURCE
	SURFICIAL GEOLOGY MAP KENORA RAINY RIVER S165 1" = 8 MILES PUBLISHED BY MINISTRY OF NATURAL RESOURCES 1965 - SURFICIAL GEOLOGY MAP THUNDER BAY S265 1" = 8 MILES PUBLISHED BY MINISTRY OF NATURAL RESOURCES 1965

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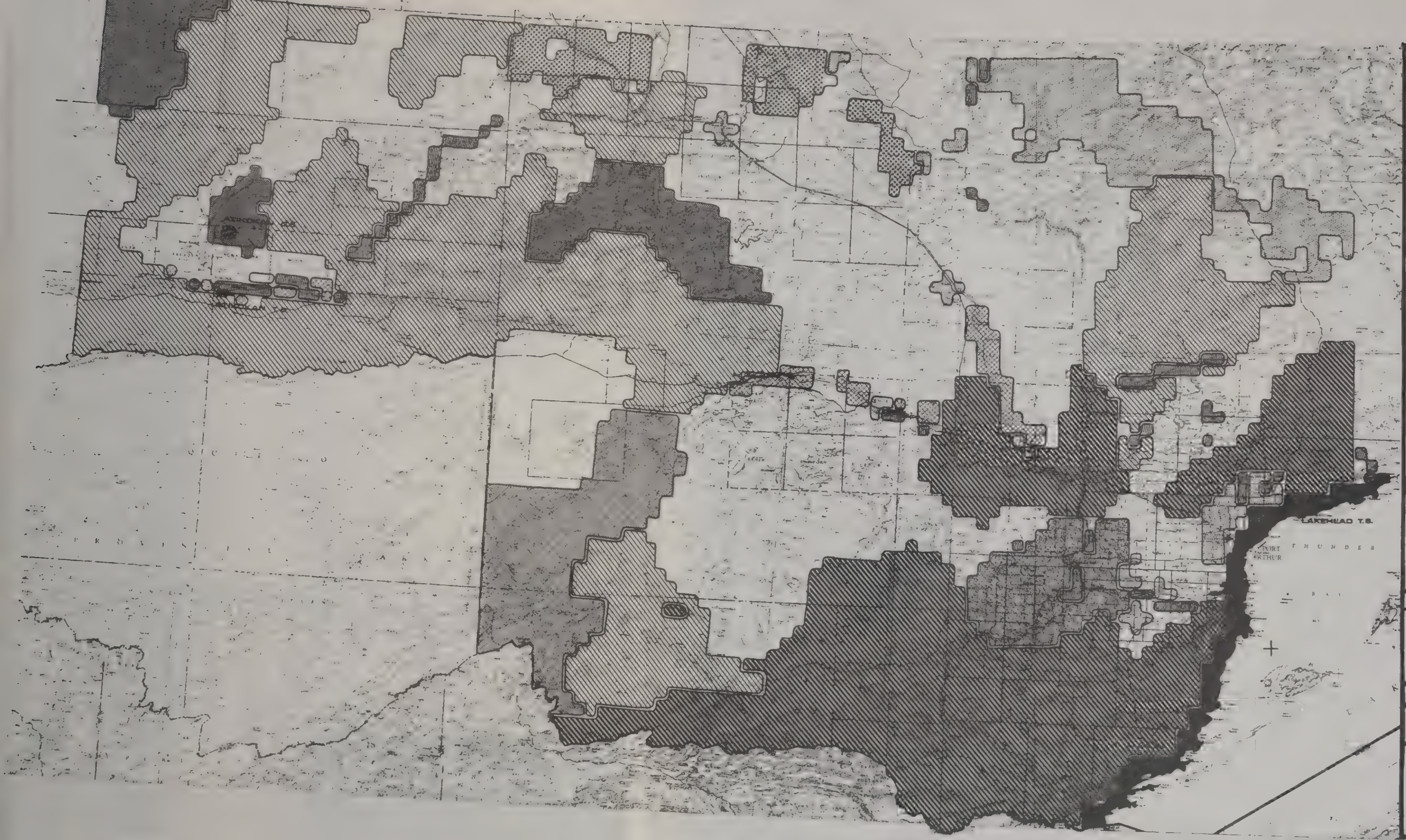
Figure 3



ROUTE SELECTION STUDY FOR W 2 (MARMION LAKE SITE)

APPEARANCE OF THE LANDSCAPE

AA: Lakeshore areas of Great Lakes

AB: Landscape units that are characterized by having numerous lakes (See units - Otter Lake, Marmion Lake and Bevidere Lake)

AD: Landscape unit - Kaministikwia, that is characterized by 200 ft. relative relief, and with little or no visual disturbance to its naturalness.

AH: Well defined "U" or "V" shaped river valleys that are still natural

AM: Landscape unit - Kakabeka Falls, characterized by 100-200 ft. relative relief (medium sized hills) and that is significantly modified by man.

AI: Landscape units - ... Lake, characterized by very little disturbance to their naturalness and having a relative relief of 1.. - 200 ft.

AJ: Landscape units - Niblock and Mack, characterized by flat to gently rolling topography (0 - 50 ft. relative relief) and their naturalness.

AK: Landscape units - Dog Lake, Quetico, Northernlight Lake, Nym Lake, Gamole Lake, Eva Lake, and Upper Scotch Lake, characterized by having a moderate number of lakes in them.

AS: Well defined "U" or "V" or gorged shaped valleys with a small degree of change to their naturalness.

AZ: Areas classified as Rural Towns or Villages

AW: Landscape units - Edmoudson Lake and Shelby Lake characterized by their rolling topography (50 - 100 ft. relative relief) and a moderate degree of disturbance to their naturalness.

AQ: Landscape units - Lappe, Oskandaga, Leckie Lake, Orbit Lake, Clay Lake, Atikokan and Antler Lake characterized by rolling topography and small sized hills with moderate disturbance to their naturalness.

NB: For full descriptions of units identified above, see "Unit Description Chart" - Volume one.

REVISION	DATA SOURCE	
	Surficial Geology Map	- Kenora - Rainy River S165
	Surficial Geology Map	- Thunder Bay S265
	Terrain Analysis	- Douglas S. Way - July 1973
	Statistics Canada	- Population index for Cities, Towns, Villages and Incorporated Places
	Air-photo Interpretation	- 1:40,000 Black & White - 1972
		- 1:60,000 Black & White - 1963
	Topographic Maps for Study Area	- 1:50,[illegible]

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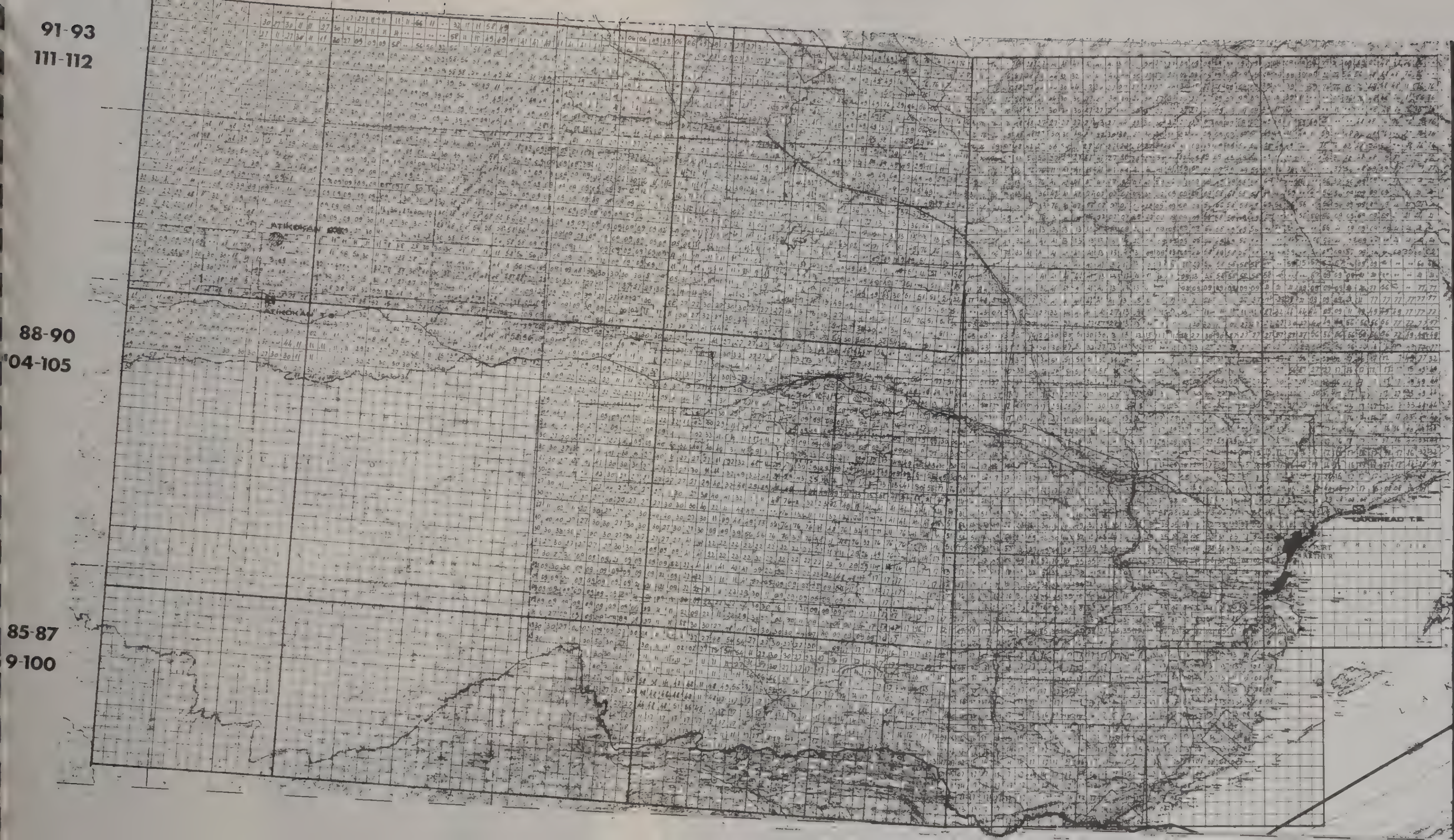
ROUTE AND SITE SELECTION DIVISION

Figure 4



ROUTE SELECTION STUDY

FOR

W 2 (MARMION LAKE SITE)

CONSTRAINTS

RANK ORDER	OBJECTIVE - FAMILY
99	WF-Restrictive & Institutional Areas
01	WD-Restrictive & Institutional Areas
02	UA,UB,UC,UD,UE-Human Settlement
03	MA-Food Production
04	MI-Food Production
05	WA-Restrictive & Institutional Areas
06	IA-Wetlands
07	QG-Timber Production
08	AA-Appearance of the Landscape
09	OA-Erodibility
10	CA-Recreation
11	GA-Surface Water
12	AB-Appearance of the Landscape
13	CB-Recreation
14	SA-Habitat
15	KA-Mineral Extraction
16	GC-Surface Water
17	AD-Appearance of the Landscape
18	MM-Food Production
19	CE-Recreation
20	CF-Recreation
21	EA-Forest Cover
22	QJ-Timber Production
23	WE-Restrictive & Institutional Areas
2[illegible]	UF,UG,UH-Human Settlement
	WC-Restrictive and Institutional Areas
27	GM-Surface Water
28	AH-Appearance of the Landscape
29	SC-Habitat
30	OF-Erodibility
31	CR-Recreation
32	KC-Mineral Extraction
33	GQ-Surface Water
35	AN-Appearance of the Landscape
36	CC-Recreation
37	CG-Recreation
38	SF-Habitat
39	QM-Timber Production
40	AI-Appearance of the Landscape
41	QP-Timber Production
42	AJ-Appearance of the Landscape
43	ON-Erodibility

RANK ORDER	OBJECTIVE - FAMILY
44	EF-Forest Cover
48	CJ-Recreation
49	KD-Mineral Extraction
51	IB-Wetlands
54	SM-Habitat
56	OU-Erodibility
57	CN-Recreation
58	AK-Appearance of the Landscape
59	CP-Recreation
60	EI-Forest Cover
61	GU-Surface Water
63	QY-Timber Production
69	AW-Appearance of the Landscape
70	RD-Timber Production
71	PD-Erodibility
72	MW-Food Production
73	HA-Surface Water
74	AQ-Appearance of the Landscape
76	BG-Timber Production
77	EN-Forest Cover
..	No objectives present in this area

REVISION	DATA SOURCE
	Each number on the map represents an "objective" and its order in terms of all of the objectives of the individual families. The twelve families of objectives are fully described in the accompanying written text (Volume I, section six), and are indicated on the series of maps F1, F2, F3, F4, F5, F6, F7, F8, F9, F10, F11 and F12. The objectives were ranked by considering the predicted degree of change and the significance of that change, that would result from constructing, operating and maintaining transmission lines in the areas as described by the various objectives.

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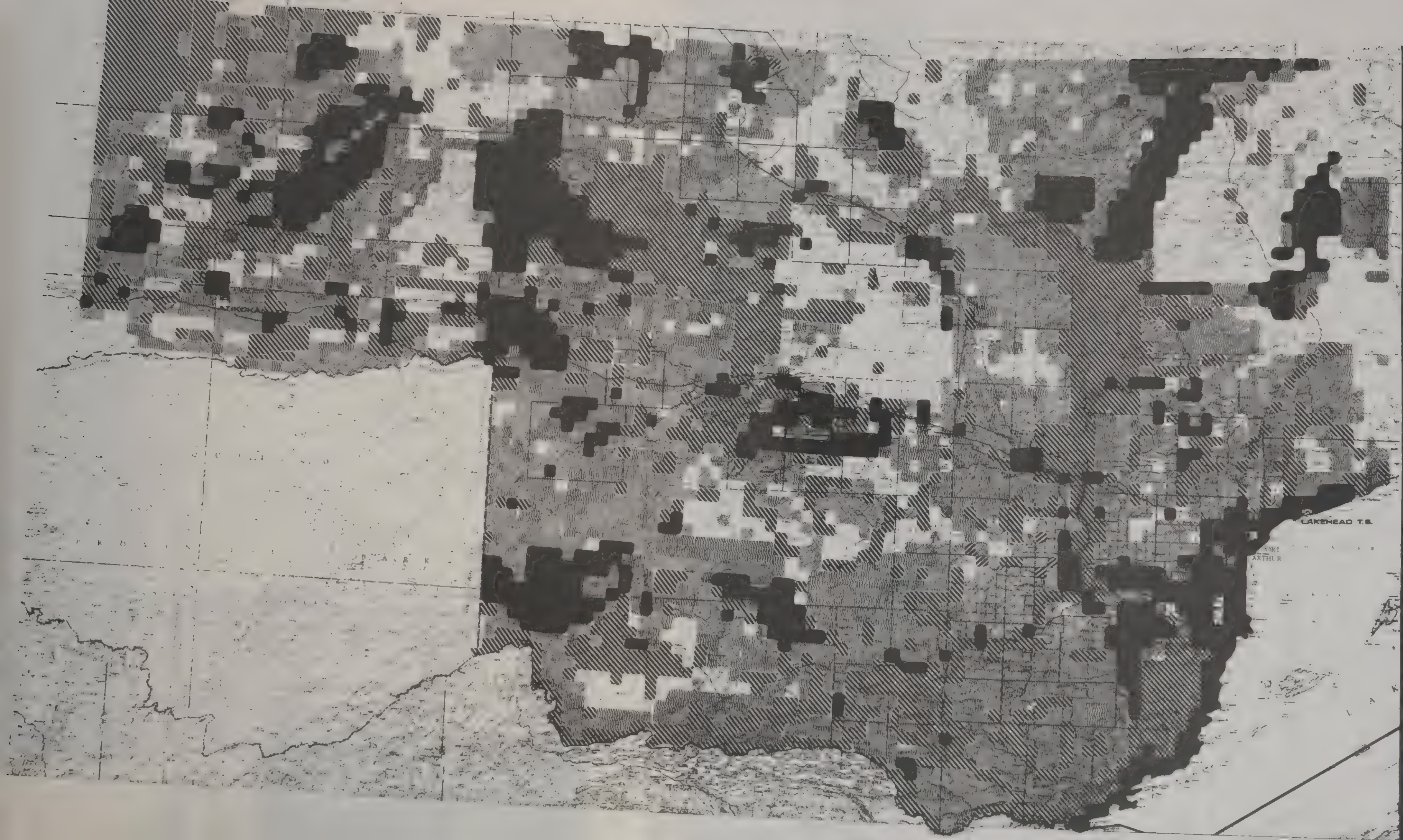
ROUTE AND SITE SELECTION DIVISION

Figure 5



ROUTE SELECTION STUDY
FOR
W 2 (MARMION LAKE SITE)

CONSTRAINT AREAS

First Order Constraints 3576 sq. km or 16.31% of the total study area

RANK ORDER	OBJECTIVE - FAMILY
99	WF-Restrictive & Institutional Areas
01	WD-Restrictive & Institutional Areas
02	UA,UB,UC,UD,UE-Human Settlement
03	MA-Food Production
04	MI-Food Production
05	WA-Restrictive & Institutional Areas
[illegible]	IA-Wetlands
[illegible]	QG-Timber Production
[illegible]	AA-Appearance of the Landscape
[illegible]	OA-Erodibility
10	CA-Recreation

Second Order Constraints [illegible] sq. km or [illegible]

RANK ORDER	OBJECTIVE - FAMILY
11	GA-Surface Water
12	AB-Appearance of the Landscape
13	CB-Recreation
14	SA-Wildlife Habitat
15	KA-Mineral Extraction
16	GC-Surface Water

Third Order Constraints [illegible] sq. km or 22.23%

RANK ORDER	OBJECTIVE - FAMILY
17	AD-Appearance of the Landscape
18	MM-Food Production
19	CE-Recreation
20	CF-Recreation
21	EA-Forest Cover
22	[illegible]-Timber Production
23	WE-Restrictive & Institutional Areas
26	UF,UG,UH-Human Settlement
	WC-Restrictive & Institutional Areas
27	GM-Surface Water
28	AH-Appearance of the Landscape

Fourth Order Constraints [illegible] sq. km or [illegible]%

RANK ORDER	OBJECTIVE - FAMILY
29	SC-Wildlife Habitat
30	OF-Erodibility
31	CR-Recreation
32	KC-Mineral Extraction
33	GQ-Surface Water
35	AN-Appearance of the Landscape
36	CC-Recreation
[illegible]	CG-Recreation
[illegible]	SF-Wildlife Habitat
[illegible]	QM-Timber Production
40	AI-Appearance of the Landscape
41	QP-Timber Production
42	AJ-Appearance of the Landscape

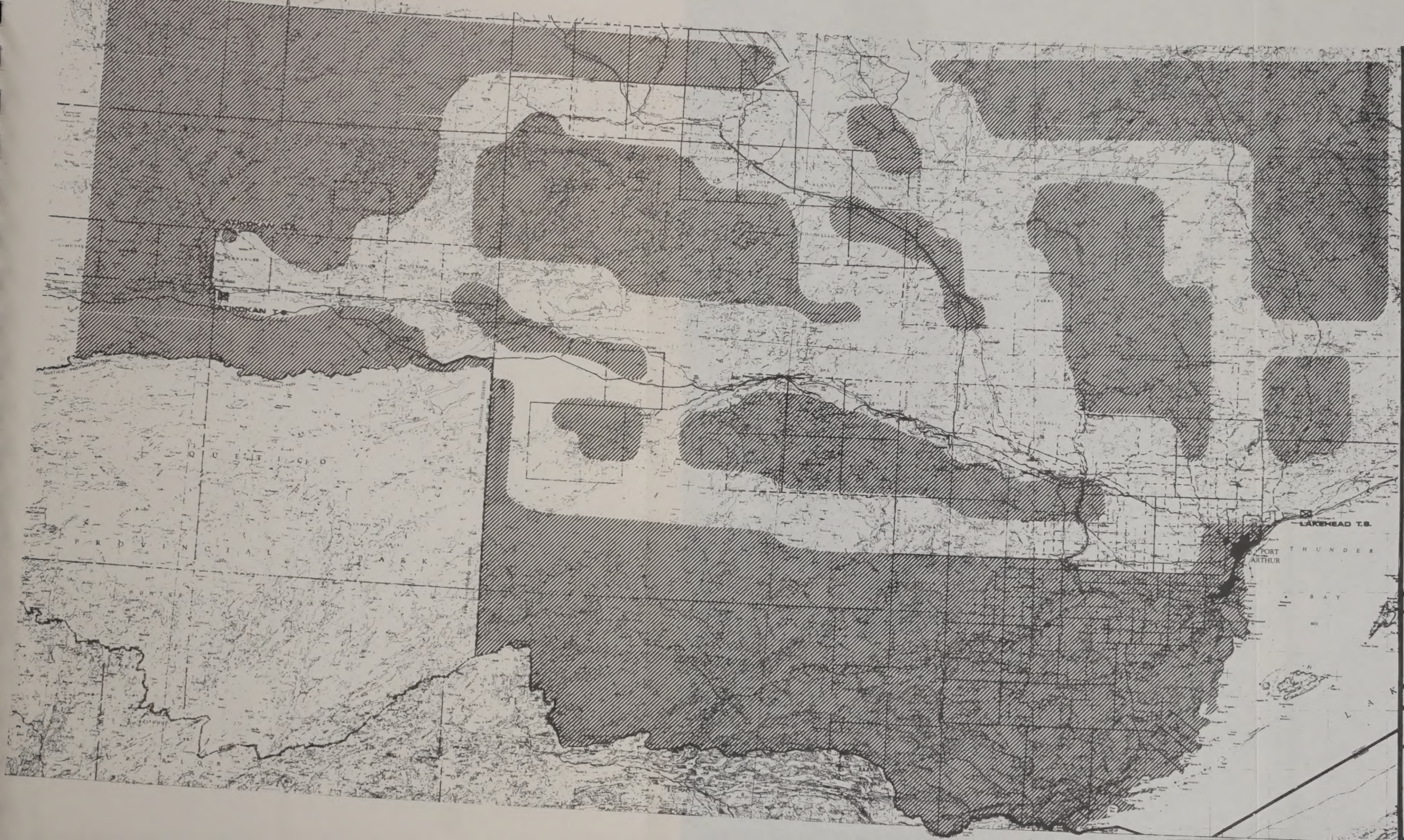
Fifth Order Constraints - 3968 sq.km or 18.10%

RANK ORDER	OBJECTIVE - FAMILY
43	ON-Erodibility
44	EF-Forest Cover
45	CJ-Recreation
[illegible]	KD-Mineral Extraction
51	IB-Wetlands
54	SM-Wildlife Habitat
56	OU-Erodibility
57	CN-Recreation
58	AK-Appearance of the Landscape
59	CP-Recreation
[illegible]	EI-Forest Cover
61	GU-Surface Water
63	QY-Timber Production
69	AW-Appearance of the Landscape
70	RD-Timber Production
71	PD-Erodibility
72	MW-Food Production
73	HA-Surface Water
76	AQ-Appearance of the Landscape
[illegible]	RG-Timber Production
77	EN-Forest Cover
..	No objectives present in this area

REVISION	DATA SOURCE
	The ranked objectives as identified on map [illegible], were grouped into five variable levels of constraint, to assist in identifying possible locations for transmission routings.

ONTARIO HYDRO
ROUTE AND SITE SELECTION DIVISION

Figure 6



ROUTE SELECTION STUDY FOR W 2 (MARMION LAKE SITE)

PRELIMINARY TRANSMISSION BANDS FROM MARMION LAKE SITE TO LAKEHEAD T.S. AND TO ATIKOKAN T.S.

TRANSMISSION BANDS

REVISION	DATA SOURCE
R1 - 19 JAN. 1976 R2 - 20 JAN. 1976	The bands (broad alternate linear "bands" within which the probability of finding suitable locations for the required transmission facilities appears greatest) were developed through considering: maps C1 & C2; the various family maps; the data maps; existing linear uses; a lake overlay map; and the system requirements.

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ROUTE AND SITE SELECTION DIVISION

Figure 7